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List of Abbreviations and Acronyms

Acronym	Meaning
AAC	Already Allocated Capacity
AC	Alternating Current; Allocation Constraint (market-coupling context)
ACER	European Union Agency for the Cooperation of Energy Regulators
aFRR	Automatic Frequency Restoration Reserve
AGC	Automatic Generation Control
AMPL	A Mathematical Programming Language
AMR	Adjustment for Minimum RAM
ANN	Artificial Neural Network
APG	Austrian Power Grid
API	Application Programming Interface
AT	Austria / Austrian bidding zone
ATC	Available Transfer Capacity (also referred to as Available Transmission Capacity)
BC	Balancing Capacity
BE	Balancing Energy
BESS	Battery Energy Storage System
BL	Base Load product
BM	Balancing Market
BM DT	Balancing Market Digital Twin
BME	Budapest University of Technology and Economics
BSP	Balancing Service Provider
CACM	Capacity Allocation and Congestion Management
CC	Capacity Calculation
CCC	Coordinated Capacity Calculation
CCCt	Core Capacity Calculation tool
CCP	Commodity Clearing Price
CCR	Capacity Calculation Region
CESZ	Continental European Synchronous Zone
CET	Central European Time
CGM	Common Grid Model
CHP	Combined Heat and Power
CIGRE	International Council on Large Electric Systems
CIP	Central Interface Point
CM	Congestion Management
CMM	Capacity Management Module
CNE	Critical Network Element
CNEC	Critical Network Element with Contingency
CPLEX	IBM ILOG CPLEX Optimizer

Acronym	Meaning
CS	Consumer Surplus
CSV	Comma-Separated Values
CV	Coefficient of Variation
CVA	Common Validation Adjustment
CZ	Czechia / Czech bidding zone
CZC	Cross-Zonal Capacity
D2CF	D-2 Congestion Forecast
DA	Day-Ahead
DA FB CC	Day-Ahead Flow-Based Capacity Calculation
DA FBMC	Day-Ahead Flow-Based Market Coupling
DACC	Day-Ahead Capacity Calculation
DAM	Day-Ahead Market
DCP	Downward Balancing Capacity Price
DD	Delivery Day
DER	Distributed Energy Resource
DLR	Dynamic Line Rating
DQC	Data Quality Check
DR	Demand Response
DSF	Distribution Sensitivity Factor
DSO	Distribution System Operator
DSO-CM	Distribution System Operator Congestion Management
DSOC	Department of System Operation and Control (IPTO)
DT	Digital Twin
EBGL	Electricity Balancing Guideline
EC	External Constraint
EET	Eastern European Time
ENTSO-E	European Network of Transmission System Operators for Electricity
EON	E.ON energy company
ESS	Energy Storage System
EU	European Union
EUPHEMIA	Pan-European Hybrid Electricity Market Integration Algorithm
EUR	Euro
EV	Electric Vehicle
FARCROSS	EU research project on cross-border electricity transmission and market integration
FB	Flow-Based
FBMC	Flow-Based Market Coupling
FCR	Frequency Containment Reserve
FFR	Fast Frequency Response
FICO	Fair Isaac Corporation

Acronym	Meaning
Fmax	Maximum admissible power flow of a network element
FRR	Frequency Restoration Reserve
GAMS	General Algebraic Modeling System
GCT	Gate Closure Time
GIS	Geographic Information System
GLSK	Generation and Load Shift Keys
HEDNO	Hellenic Electricity Distribution Network Operator
HENEX	Hellenic Energy Exchange
HETS	Hellenic Electricity Transmission System
HT	High Tariff product
HU	Hungary / Hungarian bidding zone
HUF	Hungarian forint
HUPX	Hungarian Power Exchange
HV	High Voltage
HVDC	High-Voltage Direct Current
IC	Interconnector
ID	Intraday; Identifier (context dependent)
IDA	Intraday Auction
IDC	Intraday Continuous trading
IDCC	Intraday Capacity Calculation
IDCZGT	Intraday Cross-Zonal Gate Time
IDM	Intraday Market
IEEE	Institute of Electrical and Electronics Engineers
IGM	Individual Grid Model
IPTO	Independent Power Transmission Operator
ISP	Integrated Scheduling Process
IT	Information Technology
IVA	Individual Validation Adjustment
JAO	Joint Allocation Office
JSON	JavaScript Object Notation
KPI	Key Performance Indicator
KÁT	Hungarian mandatory feed-in tariff support scheme (kötelező átvételi rendszer)
LT	Low Tariff product
LTA	Long-Term Allocation
LTN	Long-Term Nomination
LTS	Local Trading System
MAR	Minimum Acceptance Ratio
MAVIR	MAVIR Hungarian Independent Transmission Operator Company Ltd.
MC	Market Coupling

Acronym	Meaning
MCO	Market Coupling Operator
MCP	Market Clearing Price
mFRR	Manual Frequency Restoration Reserve
MILP	Mixed-Integer Linear Programming
MIQP	Mixed-Integer Quadratic Programming
MO	Market Operator
MTU	Market Time Unit
MV	Medium Voltage
NDA	Non-Disclosure Agreement
NECP	National Energy and Climate Plan
NEMO	Nominated Electricity Market Operator
NEX	Net Energy Export
NG	Natural Gas
NP	Net Position
NPF	Net Position Forecast
NRA	Non-Costly Remedial Action
NRAO	Non-Costly Remedial Action Optimisation
NTC	Net Transfer Capacity (also referred to as Net Transmission Capacity)
NTH	NEMO Trading Hub
p.u.	Per unit
PAB	Paradoxically Accepted Block
PCR	Price Coupling of Regions
PL	Peak Load product
PMB	Price Matcher and Broker software
PRB	Paradoxically Rejected Block
PS	Producer Surplus
PSS®E	Power System Simulator for Engineering
PTDF	Power Transfer Distribution Factor
PTR	Physical Transmission Right
PuTo	Publication Tool
PV	Photovoltaic
PX	Power Exchange
RAAEY	Regulatory Authority for Waste, Energy and Water (Greece)
RAM	Remaining Available Margin
RAO	Remedial Action Optimisation
RCC	Regional Coordination Centres
RES	Renewable Energy Sources
REST	Representational State Transfer
RMS	Root Mean Square

Acronym	Meaning
RMSE	Root Mean Square Error
RO	Romania / Romanian bidding zone
RR	Replacement Reserve
RTBM	Real-Time Balancing Market
SCADA	Supervisory Control and Data Acquisition
SDAC	Single Day-Ahead Coupling
SIDC	Single Intraday Coupling
SK	Slovakia / Slovak bidding zone
SLR	Static Line Rating
SM	Shipping Module
SoC	State of Charge
SQL	Structured Query Language
TRL	Technology Readiness Level
TSO	Transmission System Operator
TSO-CM	Transmission System Operator Congestion Management
TYNDP	Ten-Year Network Development Plan
UCP	Upward Balancing Capacity Price
UPRC	University of Piraeus Research Center
UTC	Coordinated Universal Time
WP	Work Package
XB	Cross-Border
XBID	Cross-Border Intraday
XBID SM	XBID Shipping Module
XLS	Microsoft Excel binary spreadsheet format
XML	Extensible Markup Language
ΔSW	Change in Social Welfare

Executive Summary

Deliverable D7.2 integrates two complementary TwinEU demonstrations into a single digital-twin framework for future electricity-market and grid operation. The Greek demonstration examines day-ahead and balancing-market operation, distributed flexibility, TSO–DSO coordination, and transmission- and distribution-grid feasibility under projected 2030 conditions. The Hungarian demonstration examines the coordinated clearing of energy and balancing capacity across day-ahead and intraday auctions, the integration of dynamic line rating into flow-based capacity calculation, and the sequential transfer of bids and network capacity between market timeframes. Together, they show how market outcomes can be generated, challenged against physical constraints, and refined in a controlled, non-operational environment.

The Greek workflow links the HENEX Day-Ahead Market Simulator, IPTO reserve and imbalance methodologies, a 15-minute Balancing Market Digital Twin, and separate PSS®E and PowerFactory validation tools. The Hungarian workflow links HUPX Labs, MAVIR balancing-capacity and capacity-calculation data, dynamic line-rating calculations, a flow-based network representation, and an AMPL/FICO Xpress co-optimised clearing engine. Both demonstrations use modular interfaces, traceable data transformations, and scenario-based execution rather than direct intervention in live markets or system operation.

The Greek results indicate substantial economic and operational value from a renewable-rich and flexibility-enabled 2030 configuration. Cleared distributed-resource transactions increase by approximately 49–77 GWh across the representative days, total social welfare rises by 22.11%–27.37%, and average day-ahead prices decline by 12.7%–55.8%, although high-RES periods also exhibit greater price variability. In the controlled 17 May comparison, 5.354 GWh of time-aggregated FCR, aFRR, and mFRR provision shifts from conventional generation to battery storage and demand response, while natural-gas generation, conventional commitment, and gas-unit ramping decrease. Transmission validation further shows that geographically distributed batteries can remove an identified Cretan line congestion, while distribution validation confirms that the assessed battery schedules remain within voltage, line-loading, transformer-loading, and state-of-charge limits.

The Hungarian results show that dynamic network information and market co-optimisation affect different parts of the market-design problem. DLR-enhanced calculations add substantial Remaining Available Margin to selected critical network elements in the evaluated day-ahead and IDA2 cases. Co-optimisation produces smaller but positive welfare gains of approximately 0.02% in the day-ahead case and 0.05% in IDA2, with favourable price effects in 37.5% of market time units. Sequential bid forwarding and capacity cascading demonstrate the value—and complexity—of linking successive auctions, while the strong sensitivity to alternative balancing-capacity bid sources confirms that data provenance and preprocessing can materially influence quantitative conclusions.

Across both demonstrations, the decisive lesson is that flexibility and transmission capacity must be valued as time-dependent, product-specific, and physically deliverable capabilities. Energy, reserve, congestion-management, and cross-zonal capacity decisions cannot be assessed independently when they compete for the same unit headroom, storage inverter capacity, demand-response availability, or network margin. Digital twins provide particular value by making these interactions auditable before market rules or operational procedures are deployed.

The work also identifies common implementation constraints. The transition to 15-minute resolution significantly increases data volume and interface complexity. Confidentiality restrictions, heterogeneous formats, incomplete network sensitivities, forecast-horizon limitations, and partly

manual exchanges remain barriers to fully automated operation. These constraints are explicitly documented so that the reported results are interpreted within their valid scope and can be reproduced or extended transparently.

Overall, the integrated Deliverable D7.2 establishes a credible European proof of concept for market–grid digital twinning. It demonstrates that digital twins can support economic market simulation, balancing and reserve co-optimisation, dynamic capacity calculation, grid-feasibility validation, and coordinated use of distributed flexibility. The combined architecture provides a strong basis for automated interfaces, uncertainty-aware simulations, wider operator validation, regulatory experimentation, and replication through the subsequent TwinEU work packages.

1 Introduction and Integrated Demonstration Framework

1.1 Purpose and Scope of Deliverable D7.2

Deliverable D7.2 presents the integrated results of the Greek and Hungarian TwinEU demonstrations in the balancing and short-term market context. Its purpose is to show how interoperable digital-twin components can reproduce technically relevant market and grid processes, test future operating arrangements, and quantify the consequences of alternative flexibility, capacity-calculation, and coordination designs without creating financial or operational consequences for the live system.

The deliverable addresses two complementary scales. The Greek demonstration focuses on the national day-ahead and balancing sequence, reserve sufficiency, distributed flexibility, TSO–DSO coordination, and physical validation at transmission and distribution level. The Hungarian demonstration focuses on coupled day-ahead and intraday markets, balancing-capacity co-optimisation, flow-based cross-zonal constraints, dynamic line rating, and sequential operation across market timeframes.

1.2 Complementary Demonstration Logic

The two demonstrations share a common principle: a market result is informative only when the data, resource constraints, and network limits that support it are represented consistently. The Greek workflow tests the movement from asset-level day-ahead schedules to balancing and grid-feasible dispatch. The Hungarian workflow tests the movement from updated network capability and balancing-capacity needs to co-optimised cross-zonal market outcomes. Their integration provides a broader view of the interfaces between energy trading, reserve procurement, flexibility activation, and network capacity.

Both pilots operate as parallel dry-run environments. They reproduce selected operational concepts, timing structures, data formats, and optimisation objectives, but they do not create binding market positions, dispatch orders, settlements, or system-security responsibilities.

1.3 Common Digital-Twin Workflow

The integrated methodology follows a modular sequence of data preparation, scenario alteration, market or balancing optimisation, result validation, and KPI assessment. Historical data provide the empirical reference, while future scenarios introduce changes in generation, demand, renewable penetration, storage, demand response, interconnection capacity, and network ratings. Results are exchanged through structured interfaces and assessed against market balances, resource constraints, and—where available—explicit transmission or distribution network models.

The common 15-minute time base is central to the integrated analysis. It enables the representation of short-duration forecast changes, reserve needs, intraday updates, ramping, battery operation, and rapidly changing network margins, while also exposing the data-governance and computational challenges associated with higher temporal resolution.

1.4 Regulatory and Operational Context

The demonstrations are aligned with the European framework for capacity allocation, market coupling, and electricity balancing. The Hungarian pilot explicitly represents CACM-based day-ahead and intraday coupling, EBGL-based balancing-capacity concepts, and co-optimised cross-zonal capacity allocation. The Greek pilot represents the national implementation of coupled day-ahead trading, the Integrated Scheduling Process, balancing-energy and reserve procurement, and the emerging need for coordinated TSO–DSO access to distributed flexibility.

The models are not intended to reproduce every legal, settlement, or control-room function. Their role is to provide a transparent test environment in which proposed market and coordination arrangements can be evaluated before implementation.

1.5 Structure of the Deliverable

Chapter 2 presents the Greek demonstration, including its system and market context, forecasting and digital-twin architecture, balancing-model formulation, TSO–DSO coordination logic, scenario design, and results. Chapter 3 presents the Hungarian demonstration, including the market and data-flow design, balancing-capacity framework, flow-based capacity calculation with DLR, scenario workflow, co-optimised clearing algorithm, and KPI results. Chapter 4 synthesises the evidence across the two demonstrations and provides unified conclusions, policy implications, replicability considerations, and next steps.

2 Greek Demonstration

2.1 Objectives, Scope, and Methodological Approach

The Greek Demo within the TwinEU project explores how digital twin technologies can transform the coordination of balancing energy and reserve markets in the context of the European energy transition. With the rising share of renewable energy sources (RES), increasing decentralisation, and the growing role of flexibility resources, system operators face unprecedented challenges in ensuring secure, reliable, and economically efficient grid operation. The Greek power system—characterised by high RES potential, geographical complexity, and ongoing market reforms—provides a representative and strategically relevant testbed for simulating future balancing scenarios.

This demonstration focuses on the use of digital twins to enhance forecasting-informed optimisation, system observability, and coordination between the Transmission System Operator (TSO), Distribution System Operator (DSO), and market actors. By integrating forecasting modules, market simulation tools, and grid validation engines, the Greek Demo aims to test how advanced scheduling of reserves and activation of distributed energy resources (DERs) can support system stability and flexibility in a realistic, scenario-based environment.

The digital twin enables comprehensive what-if analysis for 2030 conditions aligned with the National Energy and Climate Plan (NECP) by allowing users to simulate a range of structural and operational variations—such as changes in forecast patterns, reserve product configurations, and network layouts—and assess their effects on system congestion, reserve adequacy, and DER dispatch feasibility. Its modular design separates key system layers—market operations, transmission grid, and distribution grid—while ensuring consistency through shared input data and synchronised simulation horizons. This layered configuration allows both TSO and DSO perspectives to be incorporated into the evaluation of market-clearing results.

Importantly, the architecture functions entirely within a simulation environment, separate from the real-time operation of the physical power system and markets. This non-intrusive setup allows stakeholders to test control strategies, coordination schemes, and flexibility options without affecting ongoing grid or market activities. By enabling safe experimentation with future scenarios and system configurations, the digital twin fosters a transparent, iterative validation process that improves balancing market design and strengthens the integration between grid operations and market mechanisms.

Through this work, the Greek Demo contributes to the TwinEU vision of interoperable digital twins that support scalable and replicable solutions for balancing and market coordination across Europe.

2.1.1 Objectives of the Greek Demo

The Greek demonstration aims to support the future evolution of the national electricity system through the integration of digital twin capabilities that enhance market efficiency, grid security, and operational coordination. Its core objectives are:

- Enable optimal co-optimisation of balancing energy and reserve capacity, improving the efficiency, transparency, and flexibility of the balancing market under projected 2030 scenarios.
- Facilitate market-based TSO–DSO coordination, ensuring that reserve activation and DER participation are technically validated and aligned across transmission and distribution levels.

- Support the secure integration of DERs and flexibility providers, by validating their technical feasibility in real network conditions and providing structured feedback for prequalification.
- Enhance system flexibility and operational readiness, allowing scenario-based simulations that anticipate future grid conditions, interconnector usage, and reserve sufficiency.
- Contribute to policy and regulatory insight, by demonstrating the implications of market and grid coordination under NECP-aligned system changes, supporting data-driven planning and reform.

2.1.2 Role of Task 7.2 within WP7

Task 7.2 plays a foundational role within WP7 by demonstrating how advanced balancing market optimisation models can be integrated into a digital twin (DT) environment to support TSO–DSO coordination, flexibility activation, and system security. It serves as a key implementation pillar for the Greek pilot, where forecasting outputs, generated under upstream modelling activities, feed into a modular simulation chain covering reserve co-optimisation, congestion validation, and DER activation feasibility.

The task complements upstream efforts in WP2 and WP3 by translating architectural guidelines and functional building blocks into a concrete, operational pilot. Forecasting methods—that operate in alignment with WP2's data structure guidance—are used to generate inputs for market clearing and grid simulation processes. Task 7.2 demonstrates how these forecasts can be synchronised with grid constraints to produce feasible balancing schedules, thereby operationalising the forecast–optimisation feedback loop defined in WP3.

Moreover, Task 7.2 aligns with WP9 by supporting the replication and scalability of flexibility-enabling mechanisms. It provides concrete use cases and implementation patterns that inform WP9's roadmap for broader deployment. Through its modular design and harmonised data exchange logic, the task contributes to TwinEU's overarching goals of system interoperability, flexible resource participation, and cross-layer market transformation.

2.1.3 Key Innovations and Contributions

The Greek Demo introduces several technical and operational innovations that advance the state-of-the-art in balancing market coordination and digital twin-enabled grid validation. Its contributions are structured to support replicability and scalability beyond the national context, offering practical pathways to interoperability, flexibility integration, and market evolution. Key innovations include:

- Integration of four interconnected digital tools (DAM simulator, Balancing Market optimiser, TSO grid validation model, and DSO prequalification engine), enabling a comprehensive end-to-end simulation of future balancing operations across market and grid layers.
- Forecast-based co-optimisation of balancing energy and reserve capacity, incorporating multi-horizon forecasts (load, RES, EV charging) and enabling dynamic scenario-based evaluation of system behaviour under 2030 conditions.
- Grid-constrained validation at both transmission and distribution levels, allowing for iterative adjustment of DER activations, congestion-aware scheduling, and structured feedback between market and grid simulators.
- Exploration of TSO–DSO coordination models through scenario-driven dispatch simulation and DER flexibility assessments, laying the groundwork for decentralised participation in balancing markets.

- Modular, scenario-based architecture designed for transferability, enabling the reuse of logic and interfaces in other contexts and supporting long-term alignment with NECP targets and European balancing market reforms.

2.1.4 Methodological Approach

The Greek Demo applies a modular and scenario-driven approach to simulate balancing market operations using integrated forecasting, optimisation, and digital twin components. The methodology relies on actual historical data and realistic projections for the year 2030, enabling system-level testing of future balancing strategies and coordination models.

This approach allows system stakeholders to evaluate how balancing markets and grid operations will perform under varying future conditions, without disrupting current system processes. At its core, the scenario-driven methodology uses user-defined system states representing plausible 2030 configurations—based on the National Energy and Climate Plan (NECP), the Ten-Year Network Development Plan (TYNDP), and other strategic planning sources. These scenarios include structural and operational changes such as shifts in the generation mix, increased DER and storage penetration, new interconnections (e.g., Crete mainland HVDC), modified market rules (e.g., 15-minute granularity), and forecast-based reserve requirements.

The process begins with the collection and processing of real-world input data, including historical market schedules, grid topologies, and weather information. Forecasting data of multi-horizon predictions for electricity demand, RES production (PV and wind), and EV charging behaviour are exploited —separately for transmission (IPTO) and distribution (HEDNO) levels. These forecasts are integrated into a custom scenario alteration suite, which prepares modified datasets aligned with NECP targets and injects them into the Day-Ahead Market (DAM) and Balancing Market (BM) simulation engines.

Optimisation routines are then executed: the DAM module solves the market-clearing problem under forecast-based scenarios, while the BM engine performs grid-constrained co-optimisation of balancing energy and reserve products. Outputs from both solvers are used to generate dispatch schedules that are passed to the transmission and distribution grid simulators for technical validation.

The TSO and DSO tools assess congestion, voltage, and loading limits, identifying infeasibilities and returning structured feedback to adjust DER activations. This iterative simulation process allows scenario testing under various system conditions, helping evaluate the operational impact of different coordination models. The architecture supports feedback loops and modular component integration, providing a realistic environment for balancing market design, flexibility analysis, and TSO–DSO interaction under future grid conditions.

2.1.5 Structure of the Deliverable

Within the integrated Deliverable D7.2, the original Greek Demo contribution is retained in the following sections:

I. Section 2.2 introduces the Greek system and market context, outlining the operational, regulatory, and structural drivers for implementing a digital twin in the balancing market domain.
II. Section 2.3 presents the forecasting models and digital twin architecture, describing how predictive insights, optimisation tools, and grid validation components are integrated across transmission, distribution, and market layers.

III. Section 2.4 details the balancing market simulation model, including its co-optimisation logic, interaction with forecast inputs, and role in enabling TSO–DSO coordination.
IV. Section 2.5 presents the scenario-based simulation results, illustrating how the digital twin is used to test future market configurations, reserve allocation, and DER integration strategies under 2030-aligned conditions.
V. Section 4.1 retains the Greek Demo conclusions and policy recommendations, while Sections 4.3 and 4.4 provide the integrated cross-demonstration synthesis and common future perspectives.

2.2 System and Market Context

This section sets the foundation for the Greek Demonstrator by presenting the operational, regulatory, and institutional landscape of the national power system. It offers a detailed portrayal of the infrastructure and market mechanisms that shape electricity generation, transmission, distribution, and trading activities in Greece. The content provides the essential context required to understand the environment in which balancing operations, flexibility services, and coordination between system operators are carried out. Emphasis is placed on the configuration and functioning of the transmission and distribution networks, the evolving energy mix, interconnection strategies, and the organization of energy and ancillary service markets. It also introduces the roles of key actors—such as IPTO, HEDNO, and HENEX—and explains how they contribute to operational planning and market functioning. In doing so, this section bridges the physical electricity system with the digital modeling approach that follows, laying out the real-world assumptions and constraints that inform the simulation framework and optimization logic of the Greek Digital Twin.

2.2.1 Overview of the Greek Transmission and Distribution Grids

This section presents the structural and operational characteristics of the Hellenic Electricity Transmission System (HETS), which constitutes the backbone of Greece's high and extra-high voltage electricity infrastructure. It aims to describe the main components, interconnections, and energy flows that define the national transmission network. Emphasis is placed on the physical extent of HETS, its voltage levels, and the substations forming the grid. The section also highlights major transmission projects, including interconnections with the island of Crete and neighboring countries. Furthermore, it outlines the configuration of electricity generation units connected to HETS, both from conventional and renewable energy sources. Statistical data regarding production capacity, fuel mix evolution, and RES integration are provided to illustrate recent developments. The section additionally explores annual electricity demand patterns and peak load conditions. It concludes by addressing key factors considered in system planning. This information collectively supports a comprehensive understanding of the current status and strategic direction of the Greek transmission system.

2.2.1.1 Hellenic Electricity Transmission System (HETS)

The Hellenic Electricity Transmission System (HETS) comprises high-voltage overhead lines, underground and submarine cables, and substations operated at 400 kV, 150 kV and 66 kV. It transmits electricity across mainland Greece and interconnected islands and links the Greek system with neighbouring countries. As of December 2024, it included approximately 13,714 km of 66 kV, 150 kV and 400 kV transmission circuits and 428 substations at 150 kV and 400 kV [1].

2.2.1.1.1 Crete island interconnections

Crete is Greece's largest island and historically relied heavily on fossil-fuel generation. The island ceased to be electrically isolated in 2021, when the 150 kV Crete–Peloponnese AC interconnection entered operation. The link comprises approximately 178 km of submarine cable and has a transfer capability of 2 × 200 MVA [2]. The 1 GW Attica–Crete HVDC interconnection, comprising two 500 MW subsea links of approximately 335 km, entered trial operation in 2025 and enables deeper integration of Cretan wind and solar generation [3].

2.2.1.1.2 International interconnections

Since October 2004, the Greek system has operated synchronously with the interconnected Continental European system under ENTSO-E coordination. Greece is interconnected with Albania, Bulgaria, North Macedonia and Türkiye, mainly through 400 kV AC lines, and is connected asynchronously to Italy through a 400 kV HVDC submarine link [4].

2.2.1.1.3 Electricity production

According to the December 2024 Monthly Energy Bulletin, conventional power plants connected to the HETS had an installed capacity of approximately 9.3 GW. Combined-cycle natural-gas units represented the largest share, while the remaining thermal capacity was lignite-fired and subject to the national phase-out trajectory. A further 3.2 GW of large hydroelectric capacity was connected to the system [5].

As of November 2023, RES and high-efficiency combined heat and power plants connected to the HETS and distribution network had a total installed capacity of approximately 12.2 GW, as summarised in Table 1. This included approximately 5 GW of wind capacity and 6.5 GW of photovoltaic capacity. At the same time, IPTO and HEDNO had issued connection offers for more than 15.5 GW of additional RES capacity [4].

Table 1. Capacity of RES generation stations and connection offers (November 2023).

Type	Installed Capacity	Connection offers Capacity
Wind Parks	3.9 GW (TSO) 1.1 GW (DSO)	2.8 GW (TSO) 60 MW (DSO)
Photovoltaics	0.9 GW (TSO) 5.7 GW (DSO)	10.6 GW (TSO) 1.8 GW (DSO)
Small Hydro	260 MW	104 MW
High efficiency CHP	232 MW	161 MW
Biomass & Biogas	133 MW	67 MW
Total	**12.2 GW**	**15.6 GW**

In 2024, RES accounted for approximately 48.3% of domestic electricity production, followed by natural gas at 38.7%, large hydro at 6.7%, lignite at 6.2% and other sources at 0.1%. Total domestic production reached approximately 52.1 TWh, as illustrated in Figure 1 [5].

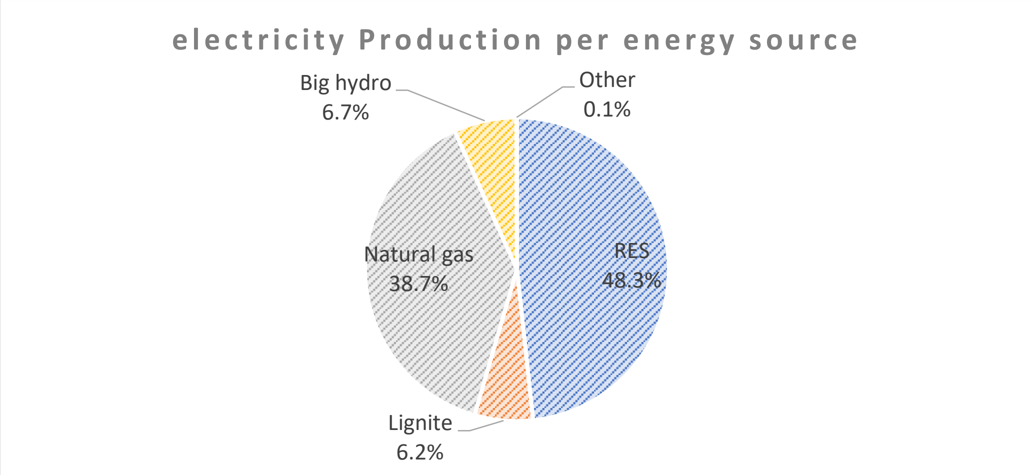


Figure 1. Energy production mix in 2024 [5].

2.2.1.1.4 Electricity demand

Annual electricity demand in Greece reached approximately 51.8 TWh in 2024, of which 41.2 TWh was supplied through the HETS; the remainder was met by generation connected to the distribution network [5]. The distribution of HETS-supplied demand by category is shown in Figure 2.

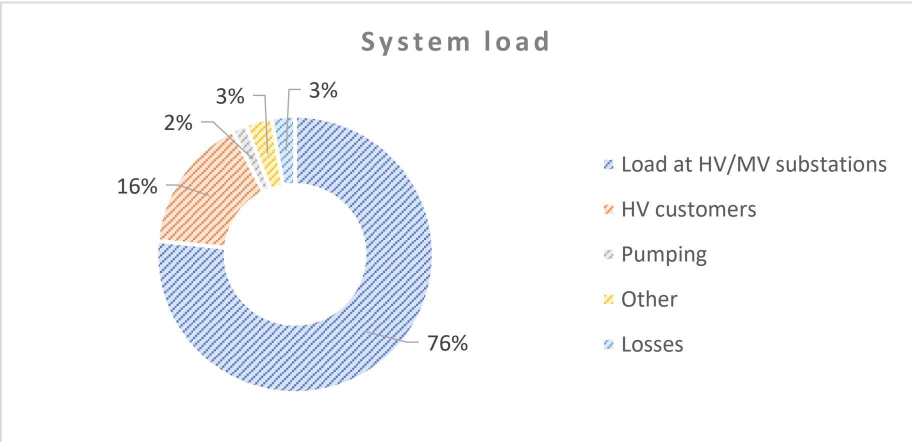


Figure 2. Distribution of annual electricity demand supplied through the HETS in 2024 [5].

Maximum system demand generally occurs during summer evening hours, whereas minimum demand is typically observed around midday in spring. Figure 3 presents the monthly maximum and minimum HETS demand in 2024. The annual maximum reached 9,266 MW in July, while the minimum fell to 331 MW in May.

The loads considered in system planning include the system load forecast, the DSO net loads in each HV/MV substation, and the forecasts of HV consumers loads (industrial etc.). The estimation of those load components is subject to many uncertainties, which are further amplified by the increasing penetration of RES.

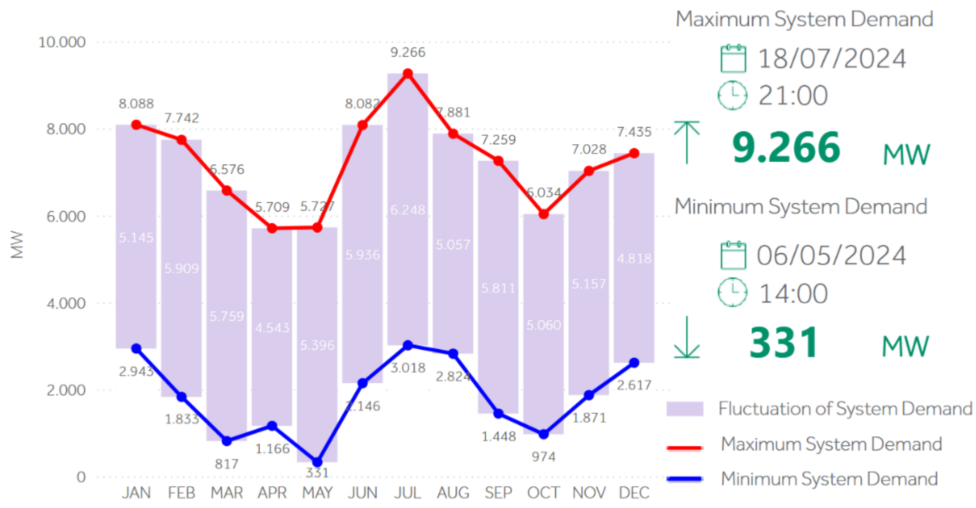


Figure 3. Maximum and minimum hourly HETS demand by month in 2024 [5].

2.2.2 Market Structure for Energy and Ancillary Services

This section explores the institutional, procedural, and regulatory framework of Greece's electricity markets, emphasizing both energy and ancillary service operations. It details how market segments—such as the Day-Ahead, Intraday, and Balancing Markets—are structured and coordinated, while highlighting the distinct roles of HENEX and IPTO. The focus is placed on how market participants interact within the broader European coupling framework and how cross-zonal exchanges are enabled through mechanisms like SDAC and SIDC. In addition, the section sheds light on the trading formats, clearing procedures, and operational timeframes involved in market participation. It also examines the procurement processes for balancing capacity and energy, including products like FCR, aFRR, and mFRR. Through a descriptive lens, the section addresses how dispatch scheduling and real-time adjustments are managed, particularly through the Integrated Scheduling Process (ISP) and the Real-Time Balancing Market (RTBM). Recent changes and forward-looking reforms, such as the move toward 15-minute time units, are also discussed. The goal is to inform how these evolving structures shape the strategic and technical foundation of demonstration activities.

2.2.2.1 Day-Ahead Market - Hellenic Energy Exchange (HENEX)

The Greek wholesale electricity market consists of the Day-Ahead Market (DAM) and the Intraday Market (IDM), which operate within the European market coupling framework through the Single Day-Ahead Coupling (SDAC) and the Single Intraday Coupling (SIDC), respectively. Within the Greek pilot of TwinEU, HENEX has developed a DAM Simulator as the core component of the Greek Electricity Market Digital Twin. Since HENEX's market-related activities focus on the Greek day-ahead market, this subsection presents the SDAC framework and the main characteristics of the Greek day-ahead market, which constitute the basis for the market modelling and simulation framework developed in the project.

The Day-Ahead Market (DAM) is the core segment of the European wholesale electricity market, where short-term energy products are traded daily ahead of physical delivery. Participants submit supply and demand orders for each Market Time Unit of the following day. The market follows a zonal model of interconnected bidding zones, where market clearing determines accepted energy quantities and market-clearing prices for each Market Time Unit. The resulting day-ahead schedules provide the reference position for physical dispatch and subsequent intraday trading.

The Day-Ahead Market operates within the Single Day-Ahead Coupling (SDAC), which integrates participating European bidding zones through a common coupled clearing process [6]. SDAC uses decentralised instances of the Price Coupling of Regions (PCR) algorithm, EUPHEMIA, to allocate available cross-zonal capacity implicitly while maximising economic surplus [7].

The Day-Ahead Market is cleared through a pan-European marginal-pricing auction, held daily at 12:00 CET (Central European Time) on the day before the delivery day (D). Under the applicable HENEX timeline, participants submit buy and sell orders before the day-ahead gate closure on D−1, and market results are published before physical delivery [8].

The auction is formulated as an optimization problem defined across two dimensions: a spatial dimension represented by interconnected bidding zones and a temporal dimension, covering the delivery day (D), divided into market time units (MTUs), i.e., the time period for which the market price is established. The auction algorithm, EUPHEMIA, solves a Mixed-Integer Quadratic Programming (MIQP) problem that aims to maximize social welfare, subject to network capacity and clearing constraints. The optimization problem takes as inputs the network topology, network constraints per MTU and the submitted market orders per bidding zone and MTU. The solution determines a single market clearing price per bidding zone and MTU, accepted energy quantities per order, and cross-border exchanges per MTU, while ensuring that electricity flows from lower-priced to higher-priced bidding zones within the limits of available cross-zonal capacity. Market clearing results are published by 14:30 CET on D-1.

Following the Day-Ahead Market, market participants may further adjust their trading positions through the Intraday Market (IDM), which operates within the Single Intraday Coupling (SIDC) framework. SIDC enables continuous trading closer to real time in response to updated forecasts, renewable generation uncertainty and changing system conditions. Unlike SDAC, which is based on a single auction, SIDC combines continuous cross-border trading through the XBID (Cross-Border Intraday) platform with three scheduled Intraday Auctions (IDAs). Continuous trading matches buy and sell orders instantly provided that sufficient cross-zonal transmission capacity is available for transactions between different bidding zones. Trading in SIDC begins shortly after the publication of the DAM results and continues until one hour before physical delivery. The three scheduled IDAs are held at 15:00 CET (D -1), 22:00 CET (D -1) and 10:00 CET (D) for the second half of the delivery day. Parallel to these auctions, the XBID continuous trading session opens at 15:00 CET (D-1) and operates on a rolling basis until 60 minutes before each market time unit, with brief halts around the IDAs.

In the context of the integration of European electricity markets, the Greek day-ahead market and intraday market are operated by the Hellenic Energy Exchange (HENEX), the designated Nominated Electricity Market Operator (NEMO) for the Greek bidding zone.

The HENEX DAM Simulator is based on the current Greek day-ahead market design while incorporating the national market developments envisaged for 2030 and the continuing evolution of the SDAC framework.

European electricity markets continue to evolve in response to increasing renewable and flexible-resource penetration. A major development incorporated in the DAM Simulator is the EU-wide transition to a 15-minute Market Time Unit in SDAC, implemented for delivery from 1 October 2025 [9].

2.2.2.1.1 The Greek day-ahead market

The Greek day-ahead market has been part of the SDAC since December 2020, initially through the coupling of the Greek bidding zone with Italy (GR-IT interconnection) and subsequently with Bulgaria (GR-BG interconnection). Its market-specific design characteristics are described below.

The Greek day-ahead market follows an asset-based representation model. In particular, conventional generation units (lignite, natural gas, large hydro and pumped hydro) and storage assets with an installed capacity above 10 MW participate at asset level, whereas renewable generation, small storage assets and electricity demand participate at portfolio level.

EUPHEMIA supports a broad set of SDAC products and order types [10]. The products available in the Greek day-ahead market are defined through the HENEX Spot Trading Rulebook and related implementing decisions [11]. The principal order categories used in the Greek bidding zone are:

- Hybrid Curve Orders, comprising price–volume pairs forming step segments and/or linear interpolation segments, submitted separately for each MTU of the delivery day and are ultimately aggregated into a single price–quantity curve per MTU.
  Priority Price-Taking Orders are hybrid step orders submitted at the applicable bidding-zone price limits. From 28 May 2026, the harmonised minimum clearing price for supply orders is −600 €/MWh, while the maximum demand price remains 4,000 €/MWh [12].
- Simple Block orders, defined by a fixed price limit, a minimum acceptance ratio and a variable quantity profile that may span multiple consecutive MTUs of the delivery day.

Unlike hybrid curve orders, simple block orders are non-convex products whose acceptance is represented through discrete decisions. A block may therefore be rejected despite being in the money, resulting in a Paradoxically Rejected Block (PRB); Paradoxically Accepted Blocks (PABs) are not permitted in the standard EUPHEMIA clearing process [7].

There exist subtypes of simple block orders eligible for trading in the Greek day-ahead market which extend the above general definition:

- Linked Block Orders, consisting of individual simple block orders linked through a parent–child relationship, where a child block order can only be accepted if its parent block order is also accepted.
- Circular Block Orders, representing a special implementation of the linked block orders, consisting of a single pair of mutually linked buy and sell blocks. Their acceptance rules require both blocks to be accepted with the same acceptance ratio or jointly rejected.
- Exclusive groups of block orders, consisting of a set of simple block orders for which the sum of the accepted ratios cannot exceed one, meaning that, in the case of fully accepted blocks, at most one block order can be accepted.

The Greek bidding zone operates with a 15-minute MTU. An exception is the Greece–Italy coupled border, which continues to operate at 60-minute resolution due to technical limitations of the underlying HVDC submarine interconnection, whereas cross-border exchanges with Bulgaria are calculated at 15-minute resolution.

Block orders are available only at 15-minute resolution, whereas curve orders may be submitted at both 15-minute and 60-minute resolution. The latter applies to the non-coupled Greek borders with Albania (GR–AL), North Macedonia (GR–MK) and Turkey (GR–TR), where cross-border flow scheduling is performed at 60-minute resolution due to operational limitations of the neighbouring TSOs.

Under the current Greek market rules, block-order access is restricted to dispatchable resources, including conventional generation, storage, dispatchable renewable portfolios and dispatchable demand portfolios [13].

2.2.2.2 Balancing market - Independent Power Transmission Operator (IPTO)

The Greek Balancing Market is operated by IPTO through a centralised, unit-based dispatch framework [14]. Balancing Service Providers submit balancing-energy and balancing-capacity offers that are assessed through successive Integrated Scheduling Process runs. The market comprises the Balancing Capacity Market, the Balancing Energy Market and the Imbalance Settlement Process [14], [15]; their operational sequence is summarised in Figure 4.

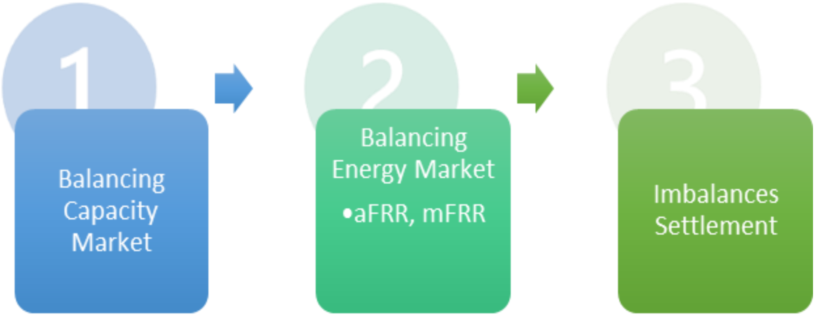


Figure 4: Time sequence of the current balancing market procedures in 2025.

The Balancing Capacity Market procures reserve capacity so that the system's forecast FCR, aFRR and mFRR requirements can be met. The Integrated Scheduling Process considers the latest market schedules, unit technical constraints, reserve requirements, network restrictions, and load and RES forecasts to determine commitment, dispatch and reserve obligations [14], [16].

A dispatch day is divided into 15-minute dispatch periods. ISP1 is executed on D−1 and is non-binding for balancing capacity; ISP2 is executed at 00:00 EET on delivery day D and is binding for the first half of the day; ISP3 is executed at 12:00 EET on D and is binding for the second half. IPTO may also execute ad-hoc ISP runs when material system conditions change [14], [16].

The Balancing Energy Market activates aFRR and mFRR to restore the power balance and maintain system frequency. mFRR is activated close to real time on the basis of submitted offers, while aFRR-capable units are dispatched automatically through AGC. The latest eligible balancing-energy offers are used by the Real-Time Balancing Market process [14], [16].

Imbalance settlement is performed after real time by comparing final scheduled positions with actual delivery or consumption. The imbalance settlement period is 15 minutes, in line with the European harmonisation of imbalance-settlement principles [14], [17].

2.2.3 Roles of IPTO, HEDNO, HENEX, Aggregators, and DERs

This section focuses on the functional division and coordinates interaction of key market and system actors involved in the Greek demo. It defines the operational mandates of IPTO, HEDNO, HENEX, aggregators, and DER owners, emphasizing how their respective roles contribute to efficient system operation and market processes. Each actor plays a critical part in enabling flexibility, maintaining grid reliability, and ensuring seamless integration of distributed resources. This section highlights how responsibilities are allocated across transmission and distribution levels, and how information is exchanged between parties to support real-time and planning decisions. Particular emphasis is placed on how digital twin tools simulate these interactions under future scenarios. The section also explains how market participation by aggregators and DERs is validated technically and operationally by the system operators.

2.2.3.1 HENEX

SDAC is implemented through coordinated business processes undertaken by TSOs and NEMOs [18]. TSOs calculate and provide cross-zonal capacities, implement shipping arrangements and manage congestion income, while NEMOs operate trading platforms, collect orders, participate in the common coupling process and publish market results. A subset of NEMOs jointly performs the Market Coupling Operator (MCO) function, including operation of the decentralised EUPHEMIA instances.

Under the European electricity market coupling framework, HENEX acts as the designated NEMO for the Greek bidding zone in accordance with Article 8 of Law 4425/2016 and Regulation (EU) 2015/1222. For its operation as a NEMO, HENEX concludes the necessary cooperation agreements with the other designated European NEMOs in accordance with Regulation (EU) 2015/1222. In this role, HENEX is responsible for operating the Greek day-ahead market by providing the trading platforms, receiving and processing market orders, managing their submission to the corresponding market coupling algorithm instance, and publishing the corresponding market clearing results for the Greek bidding zone.

In the Greek pilot of TwinEU, HENEX contributes the market layer of the Greek Electricity Market Digital Twin through the development of a Day-Ahead Market (DAM) Simulator as part of the prototype of the interconnected Greek power system. HENEX implements its operational responsibilities within the Greek Electricity Market Digital Twin through the DAM Simulator, which combines scenario generation and market-clearing optimization functionalities, providing a forward-looking representation of the Greek day-ahead market for future market assessment. Acting as the digital counterpart of the Market Operator (MO), the simulator reproduces the complete Greek day-ahead market workflow, from orderbook generation to market clearing and publication of market results. To perform market-clearing, it integrates an optimization model based on the principles of the EUPHEMIA market coupling algorithm, adapted herein using simplified assumptions suitable for simulation purposes. HENEX continuously maintains and validates the simulator, ensuring compliance with the current market design, trading rules and operational procedures, while further enhancing its scenario generation and optimization capabilities to reflect the regulatory and structural reforms leading up to 2030.

In the real Greek day-ahead market setting, HENEX interacts with IPTO during both the pre-coupling and post-coupling phases. Prior to market clearing, IPTO provides the network data, namely cross-border capacities and network constraints, required as inputs to the market clearing process. Following market clearing, the resulting market schedules and cross-border exchanges are communicated back to IPTO for system operation.

Within the Greek Electricity Market Digital Twin, the corresponding network inputs are derived from historical Greek market data available in HENEX’s Local Trading System and subsequently adapted through the integrated scenario generation processes. These model the projected evolution of the Greek electricity market through the introduction of emerging market participants, including Distributed Energy Resources (DERs), aggregators, Energy Communities and flexibility resources, together with the corresponding network topology and market adaptations agreed with IPTO for the examined future market scenarios. HENEX develops and validates the scenario generation methodology and functionalities employed by the simulator, enabling scenario-based simulations of the Greek day-ahead market that support policy assessment and facilitate long-term electricity market planning.

Following market clearing, the day-ahead market schedules generated by the DAM Simulator for the Greek bidding zone are provided to the Balancing Market (BM) component, enabling downstream coordination within the Greek Electricity Market Digital Twin.

Consequently, within the Greek Electricity Market Digital Twin, HENEX is positioned as the starting point of the market simulation workflow, providing the projected day-ahead market outcomes that drive the subsequent simulation of the interconnected Greek power system.

2.2.3.2 IPTO

The Transmission System Operator (TSO) in Greece is the Independent Power Transmission Operator S.A. (IPTO), which was established with Law 4001/2011 and was organized and operates as an Independent Transmission Operator as described in the EU Directive 2009/72/EC. The Company acts as Owner and Operator of the Hellenic Electricity Transmission System (HETS), following the provisions of Law 4001/2011, the National Grid Code and the Operation License. The role of IPTO is the operation, control, maintenance and development of the HETS, to ensure the country's supply with electricity in an adequate, safe, efficient and reliable manner, as well as the operation of the electricity Balancing Market. Due to this critical role of the Company, IPTO is taking all the necessary measures and respective procedures have been set in place to ensure its independence, transparency in its operation, strict adherence to the "equal treatment" principle for all system users and participants in the electricity market, and respect of the confidentiality of the information which IPTO manages.

Since IPTO is in general responsible for the reliable and uninterruptible operation of the electricity transmission grid, it performs, within the Greek demo, power system simulations and advanced analyses aiming to predict and examine the transmission grid operation, based on historical and forecast data for the electricity demand and RES production. It makes use of the Power System Simulator for Engineering (PSS®E) to simulate the transmission system operation under various scenarios and conditions, as defined from the DAM and BM schedules. The aim is to monitor its operational performance, identify any potential issues that may occur, such as line congestion, over- or undervoltages etc., and provide the transmission grid constraints, such as power and voltage limits, that are essential to maintain the reliable grid operation.

Within Task 7.2, IPTO provides the BM Digital Twin with load and RES forecasts, upward and downward FCR, aFRR and mFRR requirements, and forecast system imbalances relative to the DAM schedule. The transmission-grid module then assesses whether the resulting BM schedules are secure and feasible when applied to the HETS [14], [16].

In parallel, IPTO conducts rigorous validation checks on the BM DT tool developed by the University of Piraeus Research Center (UPRC) to assess its overall accuracy and constraint enforcement. Using a structured audit methodology, IPTO compares the execution outcomes of UPRC's BM DT tool against the constraints embedded in the reference ISP simulator. Crucially, to comply with strict confidentiality regulations and prevent the disclosure of sensitive operational data to external partners, IPTO evaluates the application of these constraints using UPRC's public dataset and analytical assumptions. Among other aspects, IPTO specifically verifies:

- Technical maximum and minimum unit operational limits

- Ramp-rate capabilities
- Minimum up and down times
- Maximum reserve capacities provided per Balancing Service Provider (BSP)
- Allocation of upward and downward balancing energy quantities
- Allocation of balancing reserves

as modelled in the BM DT tool.

For TSO–DSO coordination, the DSO must notify IPTO of distribution-network outages, curtailments and other actions that could materially affect HETS operation or the load and RES forecasts. RES producers and aggregators also submit updated injection forecasts before scheduled ISP executions [14].

A coordinated curtailment framework for RES and high-efficiency CHP stations is available where system balance, congestion or operational security cannot be maintained through less intrusive measures. IPTO issues curtailment instructions directly to transmission-connected plants or through HEDNO for distribution-connected resources, with execution coordinated by the DSO and, where applicable, aggregators [19].

2.2.3.3 Hellenic Electricity Distribution Network Operator (HEDNO)

HEDNO, as the national Distribution System Operator (DSO), plays a central role in validating the technical feasibility of flexibility activations within the distribution network. In the context of the Greek Pilot, HEDNO's responsibility lies in evaluating the compatibility of market-cleared Distributed Energy Resource (DER) schedules with the physical limitations of the MV network. This is accomplished through the deployment of a grid assessment tool, capable of simulating realistic grid conditions under various operating scenarios.

Following the submission of DER activation schedules from the balancing market simulation (BM Simulator), HEDNO performs scenario-based power flow analyses. These analyses determine whether proposed activations lead to local congestion, voltage violations, or transformer overloading. Based on the results, DERs are either accepted, curtailed, or rejected. This technical feedback is then structured and returned to the market platform for iterative re-optimization if needed.

HEDNO does not directly participate in market clearing or pricing mechanisms. Its role is confined to grid validation and localized constraint enforcement. By doing so, HEDNO ensures that decentralized flexibility is deployed without compromising distribution grid stability, thus enabling safe integration of DERs into balancing operations.

2.2.4 Grid Constraints and Reserve Requirements

This section outlines the technical boundaries and reserve planning criteria that underpin secure grid operation and inform the structure of balancing market activities. It explains how system-wide and zonal reserve requirements are determined, and how transmission and distribution constraints influence the feasibility of reserve activation. The roles of both the Transmission System Operator (IPTO) and the Distribution System Operator (HEDNO) are addressed, highlighting their respective approaches to maintaining operational limits and reliability margins. On the TSO side, the reserve requirements and the expected imbalance calculation approaches are described. Meanwhile, the DSO perspective focuses on localized grid conditions—including congestion points, voltage compliance, and nodal hosting capacity. The coordination between reserve dimensioning and physical grid constraints is essential to ensuring that market outcomes remain technically viable. As such, this section builds the foundation for understanding the system parameters embedded within the optimization models discussed later.

2.2.4.1 TSO side

IPTO determines the FCR, aFRR and mFRR balancing-capacity needs in accordance with the Methodology for Determination of Zonal/Systemic Balancing Capacity Needs [20]. The methodology specifies the reserve quantities required to address production–demand deviations at different time scales and to support frequency containment and restoration.

The methodology calculates the FCR, aFRR and mFRR quantities required at each 15-minute time interval of each trading day. This 15-minute time interval is consistent with the 15-minute settlement period that took effect on 1st October 2025. For each simulation day- the future date for which reserves are dimensioned- a corresponding real historical date sharing the same calendar position within the most recent available year is used for empirical data input.

- **FCR:**

FCR is dimensioned for the Continental European Synchronous Zone and allocated among control areas using the applicable pro-rata methodology. The continental requirement covers the reference incident in both upward and downward directions, while each TSO's share reflects the relative size of its control area [20].

Within this framework, the expected net generation and load of the Greek control area and for Continental Europe were projected for the forthcoming years on the basis of the National Energy and Climate Plan (NECP) and the ENTSO-E Ten Year Network Development Plan (TYNDP).

A single uniform FCR value was applied constantly across all time intervals of the simulation year, consistently with the annual averaging nature of the pro-rata allocation formula, as shown in Eq. (1).

$$FCR_{i,t} = FCR_{SE} \cdot \left(\frac{G_{i,t-2}+L_{i,t-2}}{G_{s,t-2}+L_{s,t-2}}\right) \tag{1}$$

Where,

FCR_{SE} is the total FCR value calculated for the Continental Europe Synchronous Zone, as derived from the size of the reference incident

$G_{i,t-2}$ is the sum of net generation in control area i during the penultimate calendar year relative to the year under consideration t

$L_{i,t-2}$ is the total demand load (without taking into account distributed generation connected to the distribution network) in control area i during the penultimate calendar year relative to the year under consideration t

$G_{s,t-2}$ is the sum of net generation of all control areas of the Continental Europe Synchronous Zone during the penultimate calendar year relative to the year under consideration t

$L_{s,t-2}$ is the sum of consumption of all control areas of the Continental Europe Synchronous Zone during the penultimate calendar year relative to the year under consideration t

- **aFRR**:

Each TSO in the Continental European Synchronous Zone must also maintain a minimum quantity of Frequency Restoration Reserve in both directions. For the Greek 2030 scenarios, the minimum FRR requirement is derived from projected maximum system load and divided between automatic and manual FRR in accordance with the adopted methodology [20].

Upward and downward aFRR requirements are calculated for every 15-minute interval. Upward aFRR is obtained through RMS aggregation of four components: the minimum FRR requirement ($aFRR_{min}$); the projected maximum generating-unit loss, adjusted by a load-period coefficient ($c_1 \cdot GSch_{d,t}$); projected upward deviations in cross-border schedules, adjusted by a TSO-defined timescale coefficient ($c_2 \cdot INTSch_{d,t}^{up}$) or ($d_2 \cdot INTSch_{d,t}^{up}$); and very fast load increases represented by the maximum flexible consumption in historical pumping-unit and BESS schedules ($LSch_{d,t}^{up}$), as shown in Eq. (2). Downward aFRR is obtained via the maximum operator applied to the same four component types, with the generating term replaced by the projected technical minimum generation level of the largest operating unit, scaled by a TSO-defined coefficient ($d_1 \cdot Gdev_{d,t}$), and the consumption term reflecting pumping and export schedules ($LSch_{d,t}^{dn}$), as shown in Eq. (3).

The calculation process is illustrated in Figure 5.

$$aFRR_{d,t}^{up} = \text{rms}\{(aFRR_{min}), (c_1 \cdot GSch_{d,t}), (c_2 \cdot INTSch_{d,t}^{up}), (LSch_{d,t}^{up})\} \tag{2}$$

$$aFRR_{d,t}^{dn} = \max\{(aFRR_{min}), (d_1 \cdot Gdev_{d,t}), (d_2 \cdot INTSch_{d,t}^{dn}), (LSch_{d,t}^{dn})\} \tag{3}$$

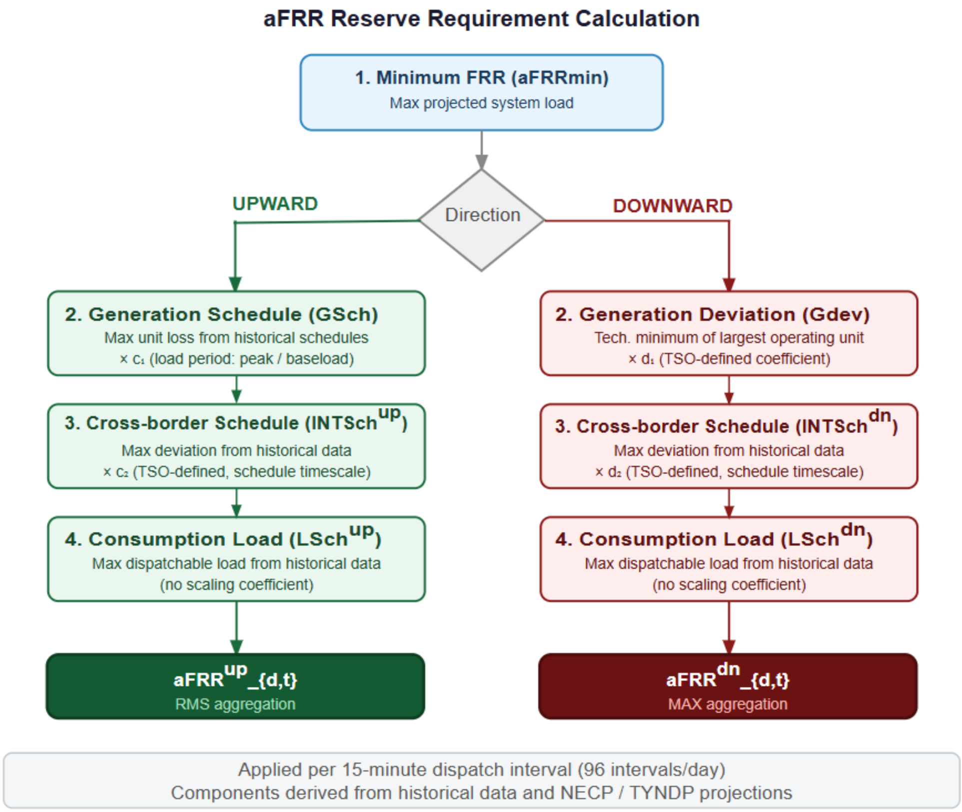


Figure 5. Upward and downward aFRR requirement calculation process.

- **mFRR:**

The upward and downward mFRR requirements are calculated for each 15-minute interval using the corresponding aFRR requirement ($aFRR_{d,t}^{up}$), RES production ($k_1 \cdot RES_{d,t}^{up}$) or ($r_1 \cdot RES_{d,t}^{up}$),, load changes ($RRLSch_{d,t}^{up}$), cross-border schedule deviations ($k_3 \cdot INTSch_{d,t}^{up}$) or ($r_3 \cdot INTSch_{d,t}^{dn}$) and, where applicable, an extreme-conditions component ($EC_{d,t}^{up}$), as shown in Eq. (4) and Eq. (5) and described in detail in [20]. In the Greek Demo, the RES and load terms are projected from comparable historical operating days and NECP-aligned capacity and demand assumptions. Upward mFRR uses RMS aggregation, whereas downward mFRR applies the maximum operator. The extreme-conditions term is not activated in the representative-day simulations, which describe plausible rather than exceptional 2030 conditions, as illustrated in Figure 6.

$$mFRR_{d,t}^{up} = \mathrm{rms}\{(aFRR_{d,t}^{up}), (k_1 \cdot RES_{d,t}^{up}), (RRLSch_{d,t}^{up}), (k_3 \cdot INTSch_{d,t}^{up}), (EC_{d,t}^{up})\} \quad (4)$$

$$mFRR_{d,t}^{dn} = \max\{(aFRR_{d,t}^{dn}), (r_1 \cdot RES_{d,t}^{dn}), (RRLSch_{d,t}^{dn}), (r_3 \cdot INTSch_{d,t}^{dn}), (EC_{d,t}^{dn})\} \quad (5)$$

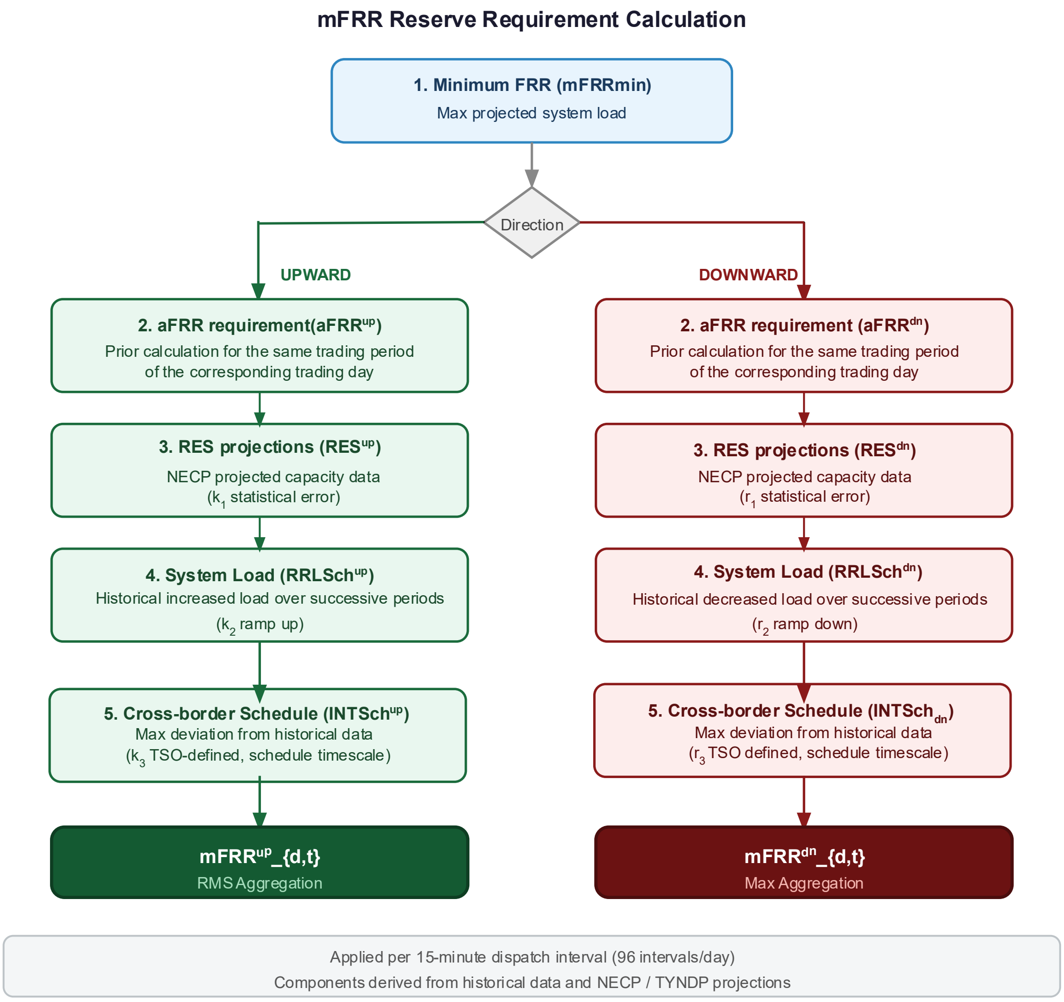


Figure 6. Upward and downward mFRR requirement calculation process.

➢ **System Imbalances:**

To maintain the system balance and efficiently allocate reserve and balancing energy, IPTO projects the 15-minute net system imbalances expected to emerge between the Day-Ahead Market (DAM) clearing and near-real-time delivery. These projected imbalances reflect the physical energy deficits or surpluses that the Balancing Market Digital Twin must resolve by activating the co-optimised balancing energy and reserve products.

To calculate the expected 15-minute system imbalance, which serves as a direct input for the BM DT tool, IPTO applies the framework established in the Greek Balancing Market Rules, adapted to model operational conditions projected for 2030. To determine the expected balancing requirements, the methodology quantifies the system deviations that emerge between the DAM results and the near real time requirements of the BM. These imbalances primarily stem from variations between initial Market Schedules and updated RES and Load demand forecasts. For the sake of simplicity, this calculation intentionally excludes imbalances resulting from unforeseen or unscheduled maintenance of generating units as well as deviations arising from cross-border commercial schedules.

2.2.4.2 DSO side

From the DSO perspective, the most critical constraints relate to local congestion (line and transformer overloading), voltage compliance at the MV level, and nodal capacity limitations for DER injection. These constraints form the foundation of HEDNO's grid validation process and are informed by detailed network models derived from GIS data and operational statistics.

Reserve requirements are defined by IPTO; however, HEDNO's role is to assess whether the distribution grid can technically accommodate DER activations proposed to meet these needs. For example, even if a DER has the capacity to provide upward reserve, HEDNO may identify limitations—such as export constraints at the node level or cumulative transformer saturation—that render full activation infeasible.

These local constraints are enforced either directly within the simulation workflow (e.g., via rejection or curtailment of DERs in violation) or indirectly, by feeding back technical limitations to the market simulator. In this way, the DSO supports the reliable realization of reserve schedules without compromising the physical integrity of the distribution grid.

In practice, the prequalification tool enforces two threshold-based violation criteria at the busbar and equipment level: bus voltage magnitude outside the [0.90, 1.10] per-unit band, and transformer or generator/PV converter loading exceeding 95% of rated capacity. The 0.90-1.10 p.u. band corresponds directly to the statutory compatibility level for steady-state voltage magnitude specified in EN 50160, which governs voltage characteristics of public MV networks and permits steady-state voltage magnitude within ±10% of nominal at the point of connection. Applying this limit as the validation threshold ensures that the prequalification tool's acceptance criteria are aligned directly with the regulatory standard governing the distribution network. Both thresholds are configurable parameters of the load-flow validation routine and are expected to be refined as the tool is calibrated against operational experience and HEDNO's internal technical rules for MV network planning.

2.3 Forecasting and Digital Twin Architecture

This section presents the structural and functional composition of the digital twin environment developed for the Greek Demonstrator, with a focus on the mechanisms that enable predictive modeling, system emulation, and coordinated market-grid analysis. It outlines the forecasting capabilities that support scenario generation and operational planning, as well as the simulation infrastructure that brings together market operations and network validation in a cohesive digital framework. The section is organised around the core forecasting models and four principal simulation tools—each with a defined role in supporting data-driven decision-making across temporal and spatial layers of the electricity system. It also details how inputs such as load forecasts, RES availability, and asset configurations are dynamically integrated into market simulators and grid analysis engines. The resulting architecture allows users to explore the performance and reliability of future balancing market designs under different operating conditions and system configurations. By establishing clear data pathways and coupling logic, this section bridges the real-world energy system context with the modeling approach described in the next stage of the methodology.

2.3.1 Forecasting Models for Demand and RES Availability

This section delves into the forecasting strategies applied within the Greek Demo to produce time-sensitive, high-resolution datasets necessary for digital market simulations and operational planning. It captures the interplay between different institutional actors—namely IPTO and HEDNO. The tools and methods described here support the accurate prediction of electricity demand and renewable output under a range of timeframes and grid conditions. Emphasis is placed on the integration of external data sources, including meteorological and historical records, alongside advanced algorithmic techniques. The forecasting architecture is tailored to supply critical inputs to both day-ahead and real-time balancing simulations. Each forecast serves a specific function, whether informing market orderbooks, reserve planning, or network feasibility checks. Scenario generation, statistical learning, and grid-aware validation processes are all embedded within the ecosystem. As such, forecasting is not treated as a standalone function but as a core pillar of active system coordination and techno-economic assessment.

2.3.1.1 TSO

IPTO's Department of System Operation and Control (DSOC) provides the demand and RES forecasts required by the DAM and BM tools. The Balancing Market framework establishes the publication and update of load and RES forecasts, while the technical requirements for the contracted wind and solar forecasting service document the principal RES data inputs and forecast process [14], [16], [23]. Forecasts may be supplied at hourly, 30-minute and 15-minute resolution, cover the mainland system and Crete, and include intraday, day-ahead and longer-horizon products.

The forecasted RES generation corresponds to the accumulated power produced by wind parks, photovoltaic parks, photovoltaic panels integrated into buildings, biomass power plants, cogeneration of heat and electricity (CHP) plants, and small-scale hydro power plants. The forecasted data is obtained from two different external providers contracted with IPTO, while the DSOC uses in-house proprietary software to conduct its own prediction used for validation. The forecasting models employed by the external providers are proprietary and are not disclosed due to privacy and confidentiality constraints. The in-house prediction tool utilizes multiple regression analysis and machine learning methods. The inputs used for all forecasting models are:

- RES plant registry
- Standing data, that is:
    - Geographical place of the RES plant
    - RES plant installed power
    - RES technology
- Historical data of RES forecasts
- Historical data of RES produced power
- Meteorological data per region, such as:
    - Ambient temperature
    - Wind speed and direction
    - Solar radiation

After collecting the forecast of the RES power from the contractors, the DSOC analyses it based on the results obtained from the in-house tool and constructs one final version of the predicted RES power profile, that is published and communicated to the DAM and BM tool.

The forecasted electricity demand corresponds to the total electrical load connected and served by the HETS (customers connected to the high voltage) and the distribution grid (customers connected to the medium and low voltage). The forecasted data is obtained from an external provider contracted with IPTO, while the DSOC uses in-house proprietary software to conduct its own prediction used for validation. The forecasting model employed by the external provider is proprietary and is not disclosed due to privacy and confidentiality constraints. The in-house prediction tool utilizes multiple regression analysis and neural network-based methods. The inputs used for the forecasting models are:

- Historical data of electricity demand obtained from SCADA measurements
- Historical forecast data of electricity demand
- Meteorological data per region, such as:
- Ambient temperature
- Wind speed and direction

After collecting the forecast of the RES power from the contractor, the DSOC analyses it based on the results obtained from the in-house tool and constructs one final version of the predicted demand power profile, that is published and communicated to the DAM and BM tool.

The forecasting workflow proceeds from RES production forecasting to total-load forecasting, collection of mandatory-hydro and commissioning-unit schedules, and determination of FRR needs. The relevant inputs are updated in the operational time windows preceding ISP1, ISP2 and ISP3 [16].

a) in the framework of ISP1 at 13:30 EET of calendar day D-1,
b) in the framework of ISP2 at 21:00 EET of calendar day D-1, and
c) in the framework of ISP3 at 9:00 EET of calendar day D.

2.3.1.2 DSO

In the context of the Greek Demo, HEDNO contributes to the simulation platform through a structured methodology for distribution-level congestion quantification, seamlessly integrated into the overall balancing optimization framework. This process operates in parallel with the forecast data of the Transmission System Operator (IPTO) and the Market Operator (HENEX) and focuses on the technical validation of proposed DER activations at the medium voltage level. The DSO forecasting model developed for the Greek Demo focuses on supporting the validation of DER activations and assessing local grid conditions under future operating scenarios. The forecasting model operates at the Medium Voltage (MV) level and is structured to generate projections for key parameters relevant to distribution grid management and flexibility assessment.

Key components of the DSO forecasting model include:

- Load Forecasting: Short-term forecasts are produced for MV substations and feeders using historical consumption patterns, temperature correlations, and time-of-day/week profiles. These are intended to reflect both current and projected 2030 demand conditions.

- PV Generation Forecasting: Forecasts for distributed PV output are based on irradiance data, temperature, panel specifications, and historical production.

The methodology is implemented through a dedicated tool built upon a high-resolution model of the MV distribution grid, reflecting both current topology and projected DER integration. For every market dispatch scenario—generated through co-optimisation of balancing energy and reserves—the tool performs deterministic power flow analyses to assess the compatibility of scheduled DER injections with grid operational constraints. These constraints include thermal limits of lines and transformers, voltage stability margins, and localized substation limits.

To support the realism and adaptability of the simulation environment, HEDNO applies a scenario-based validation process, which explores the grid's response to time-dependent DER schedules derived from market outputs. This includes the simulation of high-stress conditions—such as simultaneous activation of multiple DERs, seasonal peak loading, or unfavourable reverse flow conditions—to capture the full range of possible grid states. Each scenario is independently validated, and congestion is identified through automated checks for:

- Thermal overloads on MV feeders and distribution transformers.
- Voltage excursions at node and substation level.
- Reverse power violations in radial or sensitive network segments.

The DSO validation interface is specified to consume DER activation schedules directly from the BM Simulator's cleared output for each Market Time Unit, closing the loop between market-level co-optimisation and grid-level feasibility checking. The outcome of each validation is a structured congestion report that includes node-level export or import thresholds, DER-specific curtailment requirements, and location-specific recommendations for market reconfiguration. These results are fed back into the simulation platform in an iterative process, enabling re-evaluation of adjusted DER schedules until a feasible grid-compliant dispatch is achieved.

This approach ensures that distribution network constraints are captured dynamically and reflected in real-time decision-making within the co-optimisation process. Rather than using static rules or predefined capacity margins, HEDNO's framework delivers adaptive, scenario-informed feedback grounded in physical grid behavior. Through this contribution, the distribution network is not merely a passive endpoint but an active participant in the system-wide balancing strategy, enforcing safe and efficient utilization of flexibility resources.

2.3.2 Architecture of the Digital Twin Framework

The architecture of the digital twin developed in the context of this pilot is designed as a modular, multi-layer environment that enables the coordinated simulation of market and grid operations, with a specific focus on the balancing market. The framework supports the integration of physical system models, forecasting results, market-clearing algorithms, and grid validation tools, ensuring that different components can interact in a structured and iterative manner. Each module performs a distinct role but is connected through standardised data exchange formats, enabling seamless two-way communication between market and grid layers.

At its core, the architecture enables scenario-based simulations that assess how balancing market schedules affect system security and grid stability. Forecasting strategies generate load, RES, and system condition projections that feed into a market solver, which performs reserve co-optimisation under user-defined future scenarios. The resulting schedules are then passed to transmission and distribution grid simulators, which assess feasibility and provide constraint feedback. This feedback is re-integrated into the market models to adjust activations or dispatch logic, forming a semi-automated validation loop.

The digital twin supports what-if analysis by allowing users to configure structural and operational changes (e.g. varying forecast profiles, reserve availability, grid topology), thus evaluating their impact on congestion, reserve sufficiency, and DER activation. A key architectural feature is the separation of modules by system layer—market, transmission, and distribution—while maintaining shared input datasets and aligned timeframes. This structure ensures that both the TSO and DSO perspectives are considered when validating balancing market outputs.

Moreover, the architecture operates in a non-invasive, simulation-based setting, making it possible to test strategies and control decisions without disrupting real system operations. This allows system operators and market participants to explore the effects of coordination strategies, grid constraints, and flexibility availability before actual implementation. The result is a transparent, feedback-driven environment for testing and improving balancing market design and grid-market interoperability.

2.3.3 Description of the Four Core Tools

This section outlines the four principal modules that collectively underpin the simulation infrastructure of the Greek Demonstrator. Each module fulfils a distinct function within the integrated modelling ecosystem, enabling the representation and evaluation of market operations and grid dynamics under future-oriented scenarios. Together, they support the end-to-end simulation of electricity market processes and system behaviour across voltage levels. Specifically, the Day-Ahead Market Simulator models market clearing mechanisms for day-ahead bids under evolving policy and system conditions. Based on the DAM results, the TSO module calculates the system balancing capacity needs (i.e. aFRR, mFRR, FCR) and the system imbalances. The Balancing Market Simulator co-optimizes energy and reserve activation while integrating flexibility resources. Complementing these, the second Transmission Grid module provides high-voltage network feasibility assessments, while the Distribution Grid Tool evaluates the technical viability of DER dispatch at the medium-voltage level. Through well-defined data flows and interoperability, these tools form a coherent simulation platform capable of assessing the impact of market designs, grid constraints, and decentralized participation on system security and operational efficiency. The resulting four-module workflow is summarised in Figure 7.

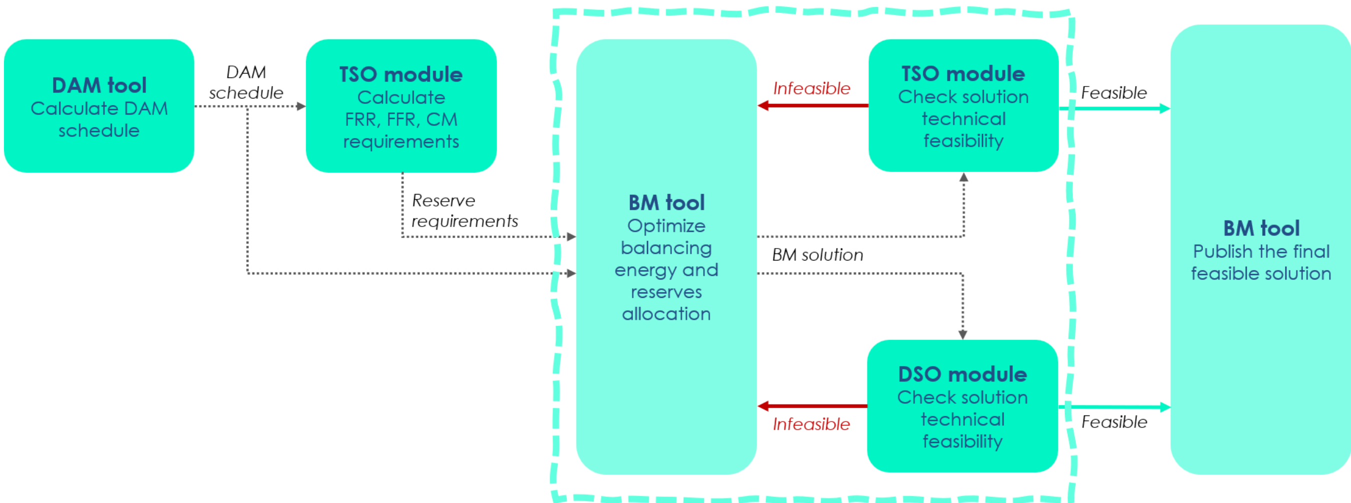


Figure 7. Four core modules of the digital twin.

2.3.3.1 DAM Simulator

The Day-Ahead Market (DAM) Simulator serves as the starting component of the Greek Electricity Market Digital Twin. It is designed to replicate the operational structure and functionality of the Greek day-ahead market as integrated into the Single Day-Ahead Coupling (SDAC), while incorporating dedicated enhancements to reflect national energy transition objectives towards 2030.

The simulator provides a comprehensive framework to model, reproduce and analyse the Greek day-ahead market under historical and projected system conditions. It maintains compliance with the actual Greek day-ahead market design, incorporating all available order types and following an asset-based representation model that enables scenario-based simulations through user-defined modifications. Built on a modular architecture, it supports scenario generation, ``what-if” analyses and market-clearing optimization, providing a flexible environment for assessing future market scenarios and strategic policy decisions.

The scenario generation capability of the Greek Electricity Market Digital Twin is enabled by the asset-based representation model of the Greek day-ahead market, which supports a technology-oriented classification of the energy mix and detailed processing of each technology’s contribution to submitted orderbook volumes. This asset-based structure provides the modelling flexibility to represent projected changes through targeted modifications at asset and technology level, thereby capturing the expected evolution of the generation mix and market participation. Using historical, altered or synthetic input data for the Greek bidding zone, the simulator constructs alternative Greek day-ahead market configurations. The corresponding market-clearing instances are subsequently solved using a custom-developed optimization model based on the publicly available description of EUPHEMIA.

The configuration of the scenario design, in terms of projection factors and asset attributes, is carried out in coordination with the Greek pilot partners based on the Greek Pilot Asset Registry. The Asset Registry serves as the common reference model, containing the technical characteristics of each asset and technology required to represent both the current and projected Greek energy system, thereby ensuring consistency across pilot components and alignment with national energy planning and operational realities.

The simulation workflow is structured into five modular stages: (1) input data generation, (2) scenario-based data alteration, (3) data preprocessing, (4) market clearing, and (5) post-clearing analysis. The core modelling and simulation logic is implemented in Python, while Julia is used to execute the market-clearing model and certain post-clearing processes. Central to this workflow are two key components: the Bidding Application, responsible for generating the DAM input datasets, and the Market Solver, which executes the market-clearing process. The simulator operates on a heterogeneous backend environment comprising Microsoft SQL Server and Oracle databases. The Bidding Application retrieves historical market data from the HENEX Local Trading System (LTS), hosted on Microsoft SQL Server, while the Market Solver stores and retrieves the generated market input datasets and market-clearing results through its dedicated Oracle database.

1. Bidding Application

The workflow begins with the generation of the Greek DAM baseline input datasets. The Bidding Application retrieves historical market data, including market participants’ orders and network data, from HENEX’s Local Trading System (LTS). The data are mapped to the assets retrieved from the common Asset Registry. They are then processed to produce the baseline market inputs for the Greek bidding zone, comprising the HENEX orderbook, network topology and network constraints. The orderbook datasets are organized, among other attributes, by Market Time Unit (MTU), delivery duration (15- and 60-minute MTUs), asset and technology.

2. Scenario Alteration Suite

Building on the baseline input datasets, the Scenario Alteration Suite follows a user-configurable, scenario-based approach for generating synthetic or altered market input datasets. Users construct a market scenario by selecting one or more simulator functionalities, each corresponding to a specific market development. Each functionality applies a predefined set of modification rules to the baseline datasets according to the selected scenario. The design of these functionalities is based on assumptions and targets outlined in national energy planning documents, including the Greek National Energy and Climate Plan (NECP) and the HETS Ten-Year Network Development Plan (TYNDP) 2024–2033, covering generation-mix changes, transmission expansion, market topology and the integration of emerging technologies such as storage and demand response [21], [22].

Each functionality is implemented as a dedicated Python function that dynamically applies targeted modifications to the market orderbook, network topology or network constraints. Depending on the user-defined scenario, the selected functions are executed sequentially, allowing multiple projected changes to be combined within a single market simulation run.

The available functionalities support modifications to:

- orderbook, (e.g., generating synthetic orders for existing or new assets, modifying submitted volumes and prices per asset technology),
- network topology (e.g., adding new interconnectors),
- network constraints (e.g., updating the Available Transfer Capacity (ATC) of an interconnector).

Within the broader library of simulator functionalities, functionalities specifically designed for modelling RES and load forecast profiles translate projected generation and demand patterns into corresponding modifications of the HENEX orderbook.

3. Data Preprocessing

Following scenario alteration, the modified Greek datasets are pre-processed into the structures required by the Market Solver. Curve orders are aggregated into price–quantity points for each MTU, while coupling data for other bidding zones include anonymised orderbooks made available through the NEMO Committee’s aggregated-curves dataset [24]. Only bidding zones for which suitable data are available are included.

4. Market Solver

The Market Solver executes a simplified EUPHEMIA-based clearing model formulated as a mixed-integer linear programming (MILP) problem for multiple bidding zones and Market Time Units (MTUs). It represents curve orders, simple and linked block orders, circular blocks and exclusive groups. Relative to the full EUPHEMIA implementation, cross-zonal exchanges are represented through ATC limits, Paradoxically Accepted Blocks are permitted for simulation purposes, and curve orders use stepwise segments [7], [25].

5. Post-Clearing Analysis

The market-clearing results are processed by the post-clearing module, which retrieves the outputs relevant to the Greek bidding zone from the Market Solver database. The module disaggregates the cleared volumes of curve orders back to the individual assets and explicitly maps the activated block-order volumes to each MTU. This process produces detailed asset-level day-ahead market schedules at 15-minute MTU resolution. To preserve data privacy, asset identifiers are pseudonymized in accordance with the standards defined by the Greek Pilot Asset Registry.

Finally, the post-clearing module exports the market clearing prices (MCPs) and asset-level market schedules, including import and export flows per interconnection, in a format compatible with the Balancing Market Simulator, enabling integration within the Greek Electricity Market Digital Twin.

The tool operates in offline simulation mode, functioning independently of real-time market operations. Data flow between modules is fully automated up to the market-clearing stage. From the post-clearing phase onward, user intervention is required to initiate result extraction and execute the disaggregation processes.

At the start of each simulation run, the user specifies a set of initialization parameters, including the delivery day, a scenario ID, and the set of simulator functionalities to be executed, identified by their corresponding parameter keys. Each functionality is referenced by a predefined parameter key and invokes a dedicated Python function that applies a specific modification to the input datasets. For example, a scenario ID of “1” may correspond to the execution of functionalities identified by keys {2, 3, 6, 8}. The session ID is dynamically generated from the delivery day in the format YYYYMMDD. Following the scenario alteration stage, the scenario-adjusted datasets are assigned a unique session identifier linked to the corresponding scenario. The new synthetic session ID is constructed by appending the scenario ID to the original session ID (e.g., YYYYMMDD1). This mechanism enables tracking and comparison of different simulation runs, whether for the same delivery day or different ones.

This workflow enables the systematic execution of alternative market scenarios while ensuring the traceability, reproducibility, and comparability of simulation results within the Greek Electricity Market Digital Twin. By providing structured scenario execution and high-resolution simulation outputs, the tool supports operational foresight, scenario analysis, and the evaluation of future Greek electricity market conditions.

2.3.3.2 BM Simulator

The Balancing Market Simulator is a mixed-integer unit-commitment and redispatch model covering one day through 96 consecutive 15-minute Market Time Units. It uses the DAM schedule as the reference position and jointly determines unit commitment, final power schedules, balancing-energy adjustments and reserve allocations for conventional generation, hydropower, aggregated BESS and demand response [26].

The objective minimises total balancing-system cost, including upward and downward balancing-energy offers, FCR, aFRR and mFRR capacity offers, TSO and DSO congestion-management services, prospective FFR, and start-up and shutdown costs. Strict production runs require every energy and service balance to close without unmet demand.

Final resource schedules remain explicitly linked to the DAM position. Thermal and hydro units are subject to technical minimum and maximum output, reserve headroom and footroom, ramp-up and ramp-down limits, minimum up and down times, start-up and shutdown logic, initial conditions and service-specific eligibility. Spinning and non-spinning tertiary capability are represented separately where required.

Energy and ancillary services are cleared simultaneously. FCR requires eligible synchronised providers; aFRR is linked to AGC-capable operating ranges; and mFRR and TSO congestion management share the available tertiary capability. This prevents the same physical headroom from being sold independently to multiple products.

Storage is represented through separate TSO- and DSO-connected aggregates with mutually exclusive charging and discharging modes, connection-level power envelopes and a daily 84% discharged-to-charged energy relation. The balancing layer does not impose a full interval-by-interval state-of-charge trajectory; detailed SoC feasibility is assessed separately in the DSO validation tool. Demand response is represented through directional, time-dependent availability limits.

Connection-level service eligibility prevents cross-level double counting. TSO-connected storage can provide balancing energy, mFRR, TSO congestion management and FFR, while DSO-connected storage is assigned to balancing energy, DSO congestion management and DSO-level FFR. Validated exogenous schedules, including fixed pumping-unit mFRR-down provision where applicable, are credited before the residual requirement is optimised.

The simulator supports separated and coordinated TSO–DSO configurations. In the separated benchmark, transmission- and distribution-level congestion-management needs are procured independently. In the coordinated case, compatible overlap may be consolidated while preserving the larger individual requirement and all local DSO feasibility conditions.

The formulation is implemented in GAMS and solved with CPLEX. Structured post-solution audits verify the balancing-energy balance and every reserve, congestion-management and FFR requirement for each 15-minute interval before results are exported. The modular implementation supports controlled scenario comparison and subsequent validation in the transmission and distribution grid tools.

2.3.3.3 TSO Modules

The TSO currently utilizes the PSS®E software to simulate high-voltage grid operation under various scenarios. This includes performing power flow simulations to identify potential network issues such as equipment congestion, e.g., in overhead lines, underground cables, transformers, and voltage limit violations. Within the TwinEU framework, the transmission grid simulation tool takes as input:

- Forecasts of electricity demand and production,
- Results from the Day-Ahead Market (DAM) simulator,
- Results from the Balancing Market (BM) Digital Twin (DT),
- The current transmission grid topology.

Using this data, the tool simulates power flows across the transmission grid and detects network issues, including line or transformer congestion and voltage limit violations.

The transmission grid results are returned to the Balancing Market Digital Twin to validate the proposed schedule. If the TSO assessment identifies a thermal or voltage violation, it communicates the relevant constraint and the schedule is revised. The iterative process shown in Figure 8 continues until a technically feasible solution is obtained.

The second TSO module, i.e. the TSO balancing requirements module, calculates FCR, aFRR and mFRR requirements and the projected system imbalances for all examined scenarios using the methodology described in Section 2.2.4.1. The calculation sequence is shown in Figure 9.

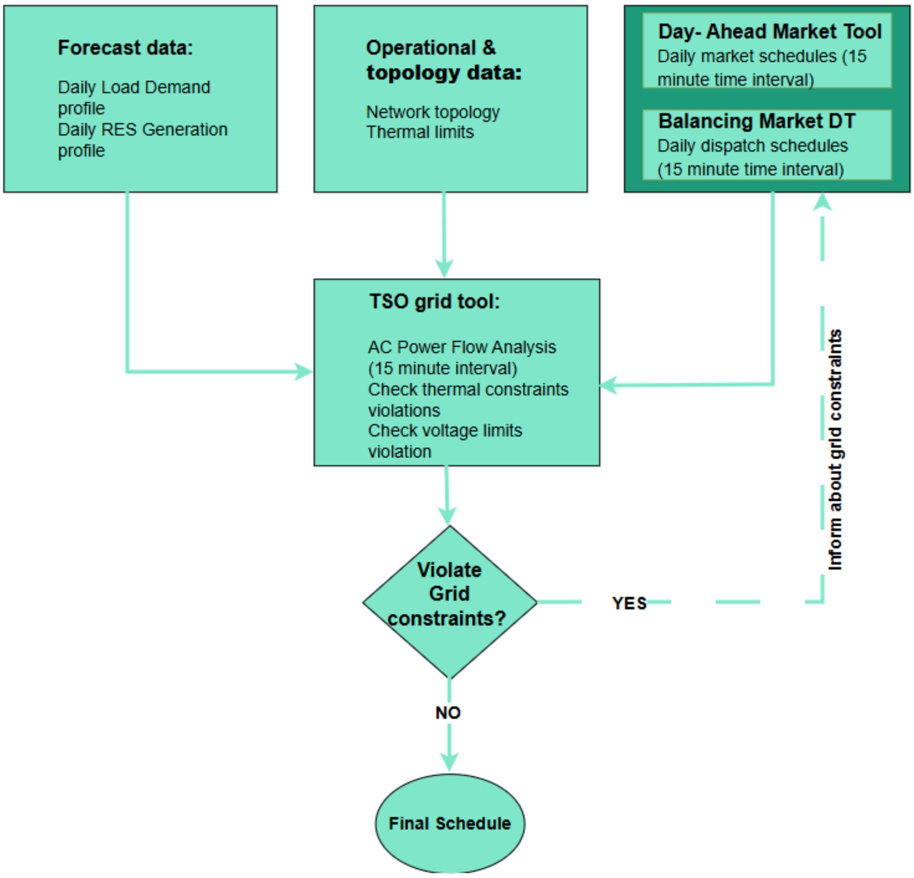


Figure 8. Architecture of the TSO grid tool for grid violation detection.

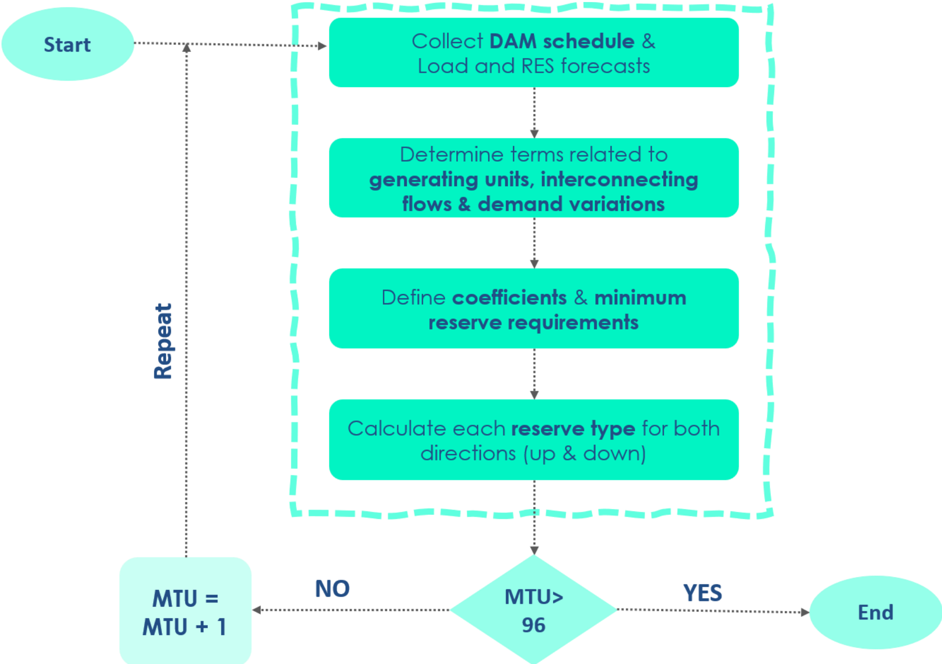


Figure 9. Process for calculating reserve requirements and system imbalances within the TSO balancing requirements module.

2.3.3.4 Distribution Grid Tool

HEDNO contributes to the simulation platform through a custom-built distribution grid assessment tool developed in PowerFactory. This tool models the MV distribution network in high detail, including topology, load allocation, line parameters, and transformer characteristics. It enables the simulation of DER activation schedules under various scenarios and stress conditions.

Inputs to the tool include:

- DER activation schedules from the BM Simulator
- Grid topology and parameters derived from GIS
- Forecasted or stress-test load scenarios

Outputs include:

- Pass/fail assessments for each DER activation
- Identification of overloaded assets or voltage violations
- Node-level technical thresholds (e.g., export limits)
- Feedback in the form of accept/curtail/reject flags for each DER

The tool does not run in real-time but rather in planning/simulation mode, supporting offline validation of market schedules. It operates iteratively: upon detecting violations, it returns structured feedback to the market layer, prompting re-evaluation of the dispatch until a feasible configuration is reached.

2.3.4 Data Sources, Interfaces, and Integration

The digital twin framework integrates a range of forecasting data, market simulators, and grid validation models, relying on coordinated data flows among key actors: the Transmission System Operator (IPTO), the Distribution System Operator (HEDNO), the Market Operator (HENEX), and DER aggregators. Each actor contributes specific datasets required for balancing market simulation, grid analysis, and reserve scheduling. The architecture is designed to ensure consistent and traceable data exchange across modules, supporting both realism and operational fidelity.

IPTO supplies historical and forecasted data for electricity demand and RES generation at the transmission level. This includes multiple time horizons (day-ahead, intra-day). These forecasts are used to inform both the DAM and BM simulation engines in case of real-time application of the DT. In parallel, HEDNO provides MV-level network data, including grid topology, equipment ratings, and loading profiles, derived from its internal GIS and operational systems. DER aggregators and pilot participants contribute data on forecasted generation and scheduled activations.

The DSO’s prequalification process relies on structured MV grid datasets (anonymized where necessary), which describe the feeder structure, voltage levels, and known technical constraints. DER activation proposals generated by the market simulator are validated in PowerFactory through load flow simulations. These simulations assess the feasibility of proposed schedules and identify required curtailments or rejections. Results are exported as structured CSV files (voltage/loading violation reports and per-asset accept/reject decisions) following a predefined feedback schema, enabling compatibility with the Balancing Market simulator; migration to a JSON-based schema is planned as the interface matures.

During this phase of the project, data exchange is managed through manual file transfers and semi-automated workflows. CSV and JSON formats are used to ensure readability and future automation compatibility. Each tool uses standardised time intervals (e.g. 15-minute Market Time Units), with temporal alignment handled by synchronisation scripts embedded in the data preparation routines.

All participating systems apply consistent naming conventions and schema versions to ensure semantic compatibility.

Although APIs are not yet implemented, the data structures and interfacing templates are intentionally designed to support future upgrades. The current feedback mechanism—where HEDNO returns DER activation statuses and IPTO and HEDNO return constraint justifications to the market model—ensures that final dispatch decisions are physically feasible and grid-compliant. This loop closes the integration between market simulation and grid validation, allowing iterative correction of schedules and establishing the foundation for real-time interoperability in future phases.

2.3.5 Digital Twin Interoperability with Market Tools

Interoperability is implemented through a modular market–grid workflow that mirrors the sequence of actual electricity-market processes. The DAM Simulator produces 15-minute market-clearing prices, asset-level schedules and cross-border exchanges, which are transferred to the BM Simulator together with forecasts, reserve requirements, expected system imbalances and technical asset data. The BM Simulator then co-optimises balancing energy and ancillary services and exports the resulting dispatch and DER-activation schedules to the TSO and DSO grid tools for physical validation.

The grid tools assess transmission congestion, voltage conditions and equipment loading, returning structured feasibility results or corrective limits to the market layer. Infeasible schedules can therefore be revised and re-evaluated until a grid-compliant solution is obtained. At the current stage, data exchange relies on traceable, semi-automated file-based interfaces using common identifiers, 15-minute timestamps, sign conventions and versioned schemas. The architecture supports downstream analysis and visualisation while preserving sensitive operator data and provides a clear migration path towards automated, API-based interoperability.

2.4 Digital Twin Functional Architecture and Integration Patterns

This section presents the mathematical and functional core of the Balancing Market Digital Twin. The balancing stage is formulated as a mixed-integer unit-commitment and redispatch problem over 96 consecutive 15-minute periods, jointly determining final resource schedules, balancing-energy adjustments and the allocation of FCR, aFRR, mFRR, congestion-management and FFR services. All decisions remain linked to the Day-Ahead Market schedule and are subject to commitment logic, ramping limits, minimum up- and down-times, technical operating ranges, shared reserve headroom, storage constraints, demand-response availability and connection-level service eligibility.

The formulation is grid-aware through explicit TSO- and DSO-level congestion requirements and validation feedback, while detailed transmission- and distribution-network feasibility is assessed by the respective external grid tools. Sections 2.4.1–2.4.5 describe the unit-commitment structure, energy–reserve co-optimisation, DER and storage representation, TSO–DSO coordination logic, and the principal assumptions and input parameters underpinning the simulations presented in Section 2.5.

2.4.1 Grid-Constrained Unit Commitment with Reserves

The balancing model is formulated as a mixed-integer unit commitment and redispatch problem that determines, in an integrated manner, the operational status of dispatchable resources, their final power schedules, the balancing-energy adjustments applied to the Day-Ahead Market schedule, and their participation in reserve and congestion-management services. The formulation is designed to reproduce the physical and market interactions that occur between the day-ahead position and the final balancing schedule, while ensuring that all energy and reserve requirements are covered by technically feasible resources.

The current case-study implementation uses a one-day scheduling horizon divided into 96 consecutive 15-minute Market Time Units. This temporal granularity is sufficiently detailed to capture intraday variations in system imbalance, renewable generation, reserve requirements, unit availability and the activation of flexible resources. It also makes it possible to represent short-duration operating transitions that would be hidden in an hourly formulation, including rapid changes in hydroelectric production, variations in battery charging and discharging, activation of demand response, and the ramping limitations of thermal units. Initial unit conditions inherited from the period preceding the optimisation horizon are used to ensure that the first 15-minute interval is consistent with the operating history of each unit.

The principal binary decisions describe whether a conventional or hydroelectric unit is online, starting up, shutting down or available for a particular operating mode. Additional binary decisions identify whether a unit is providing balancing energy in the upward or downward direction, whether it is operating under automatic generation control, and whether an offline resource is activated for non-spinning reserve. For storage, mutually exclusive charge and discharge modes are represented, while demand-response resources are assigned separate load-reduction and load-increase operating states. These discrete decisions are combined with continuous decisions for final generation, balancing-energy provision, reserve allocation, battery operation and demand-response activation. The resulting formulation is therefore able to represent both the discrete nature of commitment decisions and the continuous allocation of power and reserve capacity.

The Day-Ahead Market schedule provides the operational reference point for the balancing model. The final schedule of each dispatchable generating unit is obtained by adjusting its day-ahead position through upward or downward balancing energy. Upward balancing energy represents an increase in net system injection relative to the day-ahead position, while downward balancing energy represents a reduction in net injection. The same convention is applied consistently to all flexible technologies: battery discharging and demand reduction are upward actions, whereas battery charging and demand increase are downward actions. This linkage ensures that the balancing result remains directly traceable to the underlying market schedule and that the model does not create an independent dispatch trajectory unrelated to the day-ahead market outcome.

For each committed generating unit, the final operating point must remain between its technical minimum and technical maximum. These limits are not applied only to energy production. The model explicitly reserves sufficient upward headroom for the simultaneous provision of upward FCR, aFRR, mFRR and TSO congestion-management capacity. Similarly, the final generation level must retain sufficient downward operating margin for downward FCR, aFRR, mFRR and TSO congestion-management provision. Consequently, a unit cannot be scheduled close to its maximum output and simultaneously offer upward services beyond its remaining physical capability. Likewise, a unit operating close to its technical minimum cannot provide downward services that would require its output to fall below the minimum stable generation level. This integrated treatment prevents the double counting of the same physical flexibility across energy and reserve products.

The formulation also distinguishes between the ordinary operating range and the operating range available under automatic generation control. This is particularly relevant for aFRR, which is associated with automatically controlled generation. A unit can provide aFRR only when it is committed and technically eligible for automatic control, and its upward and downward aFRR quantities must remain within its corresponding AGC operating range. This prevents the allocation of aFRR to units that may be online but are not capable of delivering the required automatic response.

Intertemporal operating restrictions are enforced for every active thermal and hydroelectric unit. Minimum up-time constraints prevent a unit from shutting down before it has remained online for the minimum required duration following a start-up. Minimum down-time constraints prevent a unit from restarting before completing the required offline period following a shutdown. Start-up and shutdown decisions are connected through commitment-succession constraints, ensuring that changes in unit status are physically and logically consistent between consecutive Market Time Units.

Ramping restrictions constrain the permissible change in output between successive 15-minute intervals. Separate ramp-up and ramp-down capabilities are applied, and the transition into or out of operation is treated explicitly. In the natural-gas representation, a unit entering operation is required to pass through its technical minimum, while a shutdown is initiated from the technical-minimum operating region. These conditions prevent the optimiser from using instantaneous starts, instantaneous shutdowns or unrealistically large output changes to satisfy short-term balancing and reserve requirements. The initial operating status and pre-horizon output are also taken into account in the first-period ramping and commitment transitions.

Spinning and non-spinning capability are represented separately. Spinning reserve is supplied by synchronized units and is limited by their available headroom and service-specific capability. Non-spinning reserve is associated with offline but technically eligible resources and is constrained by the corresponding non-spinning reserve capability. This distinction is especially important for mFRR and TSO congestion-management services, where the model may use both synchronized flexibility and, where permitted, offline hydroelectric capability. The non-spinning representation prevents an offline unit from being treated as if it were already producing energy, while still recognising that certain resources can become available within the response time of the relevant product.

The grid dimension of the formulation is represented at the level supported by the available case-study data. Units, storage resources and demand-response portfolios are mapped to the corresponding system or control area, and the balancing-energy and reserve requirements are enforced at system or zonal level. Transmission- and distribution-related operational stress is represented through explicit TSO and DSO congestion-management requirements, which must be covered together with energy and frequency-related reserves.

It is important, however, to distinguish this grid-aware formulation from a full nodal security-constrained unit commitment model. The available dataset does not include complete transmission PTDFs, distribution sensitivity factors, individual line ratings, voltage limits or contingency-specific network models. TSO congestion-management requirements are therefore represented through a national transmission-stress proxy, while DSO congestion-management requirements are derived from distribution-side residual-load and renewable-surplus indicators. The model subsequently allocates the resulting congestion-management requirement to eligible resources under their physical operating constraints. Thus, the scheduling model captures the operational cost and flexibility implications of congestion management, but it does not claim to reproduce individual line flows or feeder voltages. A future extension with detailed network data could replace the proxy requirements with explicit transmission and distribution power-flow constraints.

The resource portfolio includes conventional generation, hydroelectric generation, TSO-connected and DSO-connected battery aggregates, demand response and pumped-storage pumping resources.

Their roles are differentiated according to technical capability and connection level. In the current configuration, TSO-connected batteries can contribute to balancing energy, mFRR, TSO congestion management and FFR, whereas DSO-connected batteries are used for balancing energy, DSO congestion management and FFR. Demand response represents controllable load reduction for upward services and controllable load increase or rebound for downward services. Its participation is restricted by time-dependent availability limits, ensuring that the model does not use more industrial or aggregated demand flexibility than is considered safely available.

The storage representation couples reserve provision to the actual operating point of each battery aggregate. A battery cannot charge and discharge simultaneously, and its final position is linked to its Day-Ahead Market position through balancing-energy adjustments. Upward services use the capability to increase net injection, either by increasing discharge or reducing charge, while downward services use the capability to reduce net injection, either by increasing charge or reducing discharge. The combined use of energy and ancillary services must remain within the battery power envelope. The model also incorporates a daily relation between charged and discharged energy to represent storage efficiency, together with separate capacity envelopes for the TSO- and DSO-connected aggregates. These constraints ensure that a battery is not treated as an unlimited source of reserve independently of its charging and discharging schedule.

Hydroelectric units are represented as dispatchable resources subject to their technical output, ramping, commitment and reserve-capability limits. In the present configuration, hydroelectric units are excluded from FCR provision, while they may contribute to aFRR and mFRR where technically eligible. Hydroelectric mFRR can include both spinning provision from online units and non-spinning provision from eligible offline units, subject to the declared non-spinning capability. This distinction allows the formulation to represent the operational flexibility of hydro resources without assuming that all hydro capacity is instantaneously available in every period.

The model also permits selected service schedules to be introduced as exogenous, validated inputs. In the 17 May configuration, the observed mFRR-down participation of the pumping units is included as a fixed profile rather than as an endogenous commitment decision. The fixed contribution is first credited against the corresponding mFRR-down requirement, and the remaining requirement is then allocated among the endogenous thermal, hydro, battery and demand-response resources. This treatment is appropriate where an observed or policy-defined service schedule must be preserved but a detailed commitment model for the corresponding pumping resources is neither required nor supported by the available data.

The unit commitment formulation is complemented by market-realism safeguards. Positive service allocations to non-storage providers are subject to a minimum accepted quantity, thereby avoiding economically or operationally meaningless fractional awards. Where activated in the relevant scenario, provider-diversification constraints require multiple resources to contribute to an active service and limit excessive concentration in a single unit. These provisions improve the robustness of the resulting schedules and reduce reliance on a single provider, while the underlying physical limits continue to determine whether each allocation is deliverable.

The optimisation is solved as a cost-minimisation problem. The objective includes the cost of upward and downward balancing energy, reserve-capacity provision, start-up and shutdown decisions, and the use of storage and demand-response flexibility. High penalty terms can be assigned to unmet requirements, while softer penalties may be used to steer the solution toward observed Integrated Scheduling Process outcomes, desired technology shares or other calibration targets. In the strict validation configuration, reserve shortages are fixed to zero, so the model must identify a physically feasible allocation that fully covers every requirement.

Finally, the model performs explicit post-solution checks of the balancing-energy and service balances. The accepted contributions of all eligible resources are compared with the corresponding requirement in every 15-minute period. The output is rejected when an unmet requirement or material balance residual is detected. This validation layer ensures that a numerically reported solution is not only optimal according to the objective function but also fully consistent with the required energy and ancillary-service balances.

2.4.2 Co-Optimization of Energy and Ancillary Services

The balancing model applies a simultaneous clearing approach in which balancing energy and ancillary-service capacity are determined within the same optimisation problem. The model does not first select an energy dispatch and subsequently assign reserve capacity to whatever headroom remains. Instead, it considers from the outset that every dispatch decision changes the capability of the same resource to provide upward and downward services. This integrated structure captures the opportunity cost of reserve provision and ensures that the final schedule is compatible with the full portfolio of system requirements.

The co-optimised products comprise upward and downward balancing energy, Frequency Containment Reserve, automatic Frequency Restoration Reserve and manual Frequency Restoration Reserve. The extended formulation additionally includes TSO congestion management, DSO congestion management and Fast Frequency Response. Each product is represented separately in the upward and downward directions, because the resources, operating margins and system conditions relevant to increasing net injection differ from those relevant to decreasing it.

The direction convention is defined from the perspective of net system injection. Upward balancing actions include increasing generator output, increasing battery discharge, reducing battery charging or reducing demand. Downward actions include reducing generator output, increasing battery charging, reducing battery discharge or increasing demand. Applying a common direction convention across generation, storage and demand response is essential for obtaining internally consistent energy and reserve balances.

FCR, aFRR and mFRR requirements are treated as exogenous system requirements for each 15-minute interval. They are read from the case-study input data and must be covered by eligible resources in the relevant direction. TSO and DSO congestion-management requirements are also introduced as time-dependent requirements, although their derivation differs from that of the established frequency products. In the 2030 case study, they are calculated from residual-load and renewable-surplus stress indicators because detailed network sensitivities are not available. FFR is treated as a prospective high-renewable-system service and is derived from a high-RES stress indicator linked to the FCR requirement. The resulting 96-period requirement set therefore combines directly provided reserve requirements with additional congestion-management and fast-response requirements developed for the future-system scenario.

For every product and Market Time Unit, the total accepted quantity from all eligible resources must equal the corresponding system requirement. Upward and downward requirements are cleared independently, but their provision is coupled through the physical limits and operating position of each resource. The model therefore does not allow upward and downward capacity to be allocated as if they came from unrelated assets. A generating unit, battery or demand-response resource must have an operating point that makes the accepted service physically deliverable.

The most important coupling arises through generator headroom and footroom. A committed unit's upward service portfolio must fit between its final generation level and its technical maximum. Its downward service portfolio must fit between its final generation level and its technical minimum. If a unit is dispatched at a high output level, its remaining capability to provide upward FCR, aFRR, mFRR or congestion management is correspondingly reduced. If it is dispatched near technical minimum, its downward reserve capability is reduced. The optimiser may therefore choose a slightly more expensive energy schedule if doing so creates valuable reserve headroom or downward flexibility elsewhere in the system.

The products are also coupled through service-specific technical capability. FCR provision is limited by each unit's primary-reserve capability and requires the unit to be synchronized. aFRR is limited by the secondary-reserve capability and requires an operating state compatible with automatic generation control. mFRR and TSO congestion management share the tertiary flexibility of the units. Consequently, the same spinning tertiary capability cannot be allocated in full simultaneously to mFRR and congestion management. Their combined allocation must remain within the unit's spinning reserve capability. The same principle applies to non-spinning mFRR and non-spinning TSO congestion-management provision, which compete for the declared non-spinning capability of eligible offline resources.

This shared-capability treatment is crucial for preventing product stacking that would be impossible in real operation. Without it, a unit with a limited quantity of available headroom could be credited separately with the full amount of mFRR and the full amount of congestion-management capacity. The model instead recognises that both services rely on the same physical response capability. The optimiser determines how the capability should be divided between products according to system requirements, service prices, alternative providers and the effect on the energy schedule.

FCR is represented as the fastest conventional reserve layer within the core balancing model. In the present configuration, it is supplied by eligible synchronized conventional units, while hydroelectric units, battery aggregates and demand-response resources are excluded from FCR where required by the scenario definition. The exclusion is implemented as a service-eligibility condition rather than through an artificial cost penalty. This ensures that an ineligible resource cannot be selected merely because its assumed offer price is low.

aFRR is co-optimised with energy through the automatic-control operating range. Both upward and downward aFRR consume available operating margin. The final dispatch must therefore place each participating unit at a point from which the accepted automatic response can be delivered without violating the unit's technical output limits. This representation also links aFRR availability to commitment: an offline unit cannot provide aFRR, and an online unit that is not placed in an eligible automatic-control state cannot be assigned the service.

mFRR is divided into spinning and non-spinning components. Spinning mFRR is provided by online units and competes with energy production and other upward or downward tertiary services. Non-spinning mFRR can be provided only by explicitly eligible offline resources and is bounded by their declared non-spinning capability. In the hydro representation, this allows selected offline hydroelectric resources to contribute to upward mFRR without being treated as continuously synchronized generators. The minimum accepted quantity and provider-eligibility conditions ensure that non-spinning awards remain operationally meaningful.

TSO congestion management is cleared simultaneously with balancing energy and frequency-restoration reserves. Upward TSO congestion management may be provided by increasing generation, increasing battery discharge, reducing demand or, where allowed, activating non-spinning hydro capability. Downward TSO congestion management may be provided by reducing generation, increasing battery charging or increasing controllable demand. Because it uses the same dispatch flexibility as mFRR, its allocation is included in the same headroom, footroom and tertiary-capability constraints.

DSO congestion management is assigned to resources connected to, or represented at, distribution level. In the current aggregation, the DSO-connected battery portfolio is the principal provider. This separation prevents TSO-connected and DSO-connected flexibility from being treated as geographically interchangeable. It also allows the model to examine the operational implications of allocating part of the flexibility portfolio specifically to distribution-level needs.

FFR is represented as a distinct fast-response requirement for the prospective 2030 high-renewable scenario. The service is primarily allocated to battery resources because of their fast response and bidirectional capability. Separate TSO- and DSO-connected FFR contributions are included, subject to the power envelope and operating point of the corresponding storage aggregate. Upward FFR uses the battery's ability to increase net injection, whereas downward FFR uses its ability to absorb additional power. FFR capacity is therefore co-optimised with battery energy, mFRR and congestion-management provision rather than treated as an independent, unlimited capability. The FFR requirement itself is a planning proxy linked to high renewable penetration and should not be interpreted as a replacement for a dynamic frequency-nadir or rate-of-change-of-frequency assessment.

Battery operation is particularly important in the co-optimisation because the same device can provide balancing energy, reserve capacity and congestion management in either direction. The model establishes a final charging or discharging point and calculates the remaining upward and downward flexibility around that point. A discharging battery can increase its upward response by increasing discharge and can provide downward response by reducing discharge. A charging battery can provide upward response by reducing charge and downward response by increasing charge. The aggregate of energy and service commitments must remain within the battery power limit, and charge and discharge remain mutually exclusive.

The battery model also preserves intertemporal energy consistency at daily level. Discharged energy is linked to charged energy through the assumed efficiency, while the separate TSO- and DSO-connected aggregates are subject to their respective power and allocation assumptions. This prevents the model from repeatedly using storage for balancing and reserve provision without accounting for the energy required to sustain the battery schedule.

Demand response is modelled as a controllable modification of electricity consumption rather than as generation. Load reduction provides an upward system response, while controlled load increase or rebound provides a downward response. The accepted reserve stack of the demand-response portfolio cannot exceed the operating flexibility available in the corresponding period. Demand response is used selectively for the services for which it is considered operationally suitable, principally mFRR and TSO congestion management in the current configuration. Time-dependent availability limits prevent the model from activating demand response outside the assumed industrial or aggregated-load flexibility windows.

The co-optimisation does not rely on a rigid sequential priority order between natural-gas units, hydroelectric units, batteries and demand response. All technically eligible providers are evaluated together through their offer costs, available capacity, commitment state and interactions with the other products. Scenario-specific eligibility restrictions or fixed schedules are imposed explicitly, but the remaining requirement is cleared economically. This is preferable to a sequential process because a seemingly inexpensive allocation in one product can create a substantially more expensive or infeasible outcome in another product.

For example, allocating a large upward mFRR quantity to a thermal unit may require the unit to be dispatched below its energy-optimal output in order to preserve headroom. The lost energy may then need to be replaced by another unit. Similarly, assigning downward reserve to a hydroelectric unit can restrict its minimum feasible output, while assigning multiple services to a battery can reduce its available charging or discharging margin. The co-optimised objective internalises these interactions and selects the least-cost feasible combination for the complete service portfolio rather than the cheapest provider for each product in isolation.

The objective function includes balancing-energy costs, reserve-capacity offer costs, start-up and shutdown costs, and the operating costs associated with storage and demand-response activation. Unmet-requirement variables are associated with prohibitive penalties during model development and are fixed to zero in the strict production runs. This establishes a clear hierarchy: system feasibility and complete requirement coverage are mandatory, while economic optimisation determines how the requirements are distributed among feasible providers.

Provider-diversification conditions further improve the operational credibility of the clearing result. A minimum number of providers may be required for active conventional services, while the share assigned to any individual provider may be limited. The intention is to avoid schedules in which an entire system requirement is concentrated in one unit despite the availability of a wider provider pool. These conditions can also provide robustness against non-delivery by individual units and represent practical procurement considerations not captured by cost minimisation alone.

The final outcome of the co-optimisation is a complete 15-minute schedule containing the final operating point of each resource, upward and downward balancing-energy quantities, and the allocation of every reserve and congestion-management product. The schedule is subjected to an independent balance audit. For each Market Time Unit, the model verifies that the accepted provider quantities exactly reproduce the relevant requirement and that no shortage remains. Separate checks are performed for balancing energy, FCR, aFRR, mFRR, TSO congestion management, DSO congestion management and FFR. This audit provides a transparent link between model decisions, system requirements and the output tables used for subsequent analysis in Deliverable 7.2.

2.4.3 DER, Storage, and Prosumer Flexibility Representation

Distributed energy resources, storage systems and prosumer-side flexibility are represented within the balancing model as market-facing flexibility portfolios that participate directly in the same 15-minute optimisation used for conventional generation, balancing energy and ancillary services. The formulation therefore does not treat decentralised flexibility as a subsequent adjustment applied after the unit-commitment solution. Instead, the availability and operation of these resources are considered simultaneously with thermal and hydroelectric dispatch, reserve allocation, congestion management and the system-imbalance requirement.

The current implementation adopts an aggregated connection-level representation rather than modelling individual residential, commercial or industrial devices. This choice is consistent with the granularity of the available case-study data and with the role of an aggregator in electricity-market participation. Individual batteries, controllable loads, or other prosumer assets are assumed to be combined into portfolios that submit a common flexibility offer to the balancing model. The optimisation therefore interacts with the aggregate flexibility envelope exposed by the aggregator rather than with the operating constraints of every individual end-user device.

This representation has two advantages. First, it limits the computational burden of the mixed-integer optimisation while retaining the principal physical characteristics of decentralised flexibility. Second, it is consistent with the practical organisation of flexibility markets, where small resources are generally represented by an aggregator or flexibility service provider. The aggregate flexibility envelope is interpreted as the amount of power that has already been validated by the aggregator after accounting for internal portfolio constraints, customer availability and the technical capabilities of the participating assets.

In the present Greek case study, decentralised flexibility is represented primarily through two aggregated battery portfolios and one aggregated demand-response portfolio. The battery resources are differentiated by connection level: one aggregate represents storage connected at, or operationally associated with, the transmission-system level, while a second aggregate represents storage connected at distribution level. The demand-response portfolio represents controllable demand connected to the TSO-side flexibility framework. Pumped-storage pumping resources are represented separately. The overall formulation is therefore sufficiently differentiated to prevent transmission- and distribution-connected flexibility from being treated as geographically or operationally interchangeable.

Non-dispatchable renewable generation is not treated as an independent flexibility provider in the present configuration. Photovoltaic and wind production contributes to the system operating conditions, renewable penetration, residual load and the calculation of congestion-management and FFR requirements. However, these resources do not submit endogenous balancing and reserve bids unless explicit controllability, curtailment or reserve-capability data are available. This avoids attributing flexibility to renewable resources without evidence of prequalification, controllability or locational deliverability. The active DER flexibility layer is therefore concentrated on batteries, controllable demand and the explicitly represented pumping resources.

2.4.3.1 Aggregated flexibility bids

Each flexible portfolio is represented as a market participant capable of submitting upward and downward flexibility offers for the products for which it is eligible. The offer structure distinguishes between balancing-energy offers and reserve-capacity offers. Balancing-energy bids determine how the final operating position of the portfolio may deviate from its Day-Ahead Market position. Reserve bids represent capacity that is maintained available for activation in response to frequency, balancing or congestion-management needs.

The offer quantities are continuously divisible within the declared technical limits. Consequently, the optimisation may accept all or part of an aggregate bid. Binary operating variables are used only where they are required to describe mutually exclusive operating modes, such as battery charging versus discharging or demand reduction versus demand increase. This combination of continuous bid acceptance and binary operating-mode decisions allows the model to capture the operational flexibility of aggregated portfolios without assuming that every individual underlying asset is independently dispatched by the system operator.

Offer prices are incorporated into the common system objective together with conventional generation, start-up and shutdown costs, balancing-energy costs and reserve-capacity costs. The model therefore evaluates the opportunity cost of using decentralised flexibility in one product rather than another. A battery may, for example, be economically attractive for balancing energy but retaining part of its power capability for FFR or congestion management may produce a lower total system cost. Similarly, demand response may be reserved for a period in which its contribution to mFRR or congestion relief is more valuable than an earlier activation.

The Day-Ahead Market schedule is the reference position for storage and other market-participating flexible resources. Upward and downward balancing energy are defined relative to that baseline, and the final operating schedule is determined jointly with reserve awards. This ensures that the model does not create an independent storage or prosumer schedule detached from the market position already established before the balancing stage.

2.4.3.2 Battery-storage representation

Battery storage is represented through separate charging and discharging quantities for every 15-minute Market Time Unit. Discharge increases net system injection, while charging reduces net injection. The two operating modes are mutually exclusive, meaning that an aggregate cannot charge and discharge simultaneously in the same interval. Binary mode variables enforce this condition, while a minimum non-zero operating level avoids artificial solutions in which the battery is nominally active at an economically or operationally insignificant quantity.

The final battery operating point remains explicitly linked to the corresponding Day-Ahead Market position through upward or downward balancing-energy adjustments. A battery that was scheduled to charge in the day-ahead market may provide upward balancing flexibility by reducing its charging level or, where sufficient flexibility exists, by moving toward discharge. Conversely, a discharging battery may provide downward balancing flexibility by reducing its output or moving toward charging. This representation captures the full bidirectional value of storage rather than treating charging and discharging as unrelated resources.

The aggregate storage portfolio has a total power envelope of 1,730 MW in the current scenario. This envelope is divided by connection level, with 70% assigned to the TSO-connected aggregate and 30% to the DSO-connected aggregate. The corresponding power envelopes are therefore 1,211 MW and 519 MW. These values are applied as physical upper bounds on the combined operating position and eligible ancillary-service commitments of the respective storage portfolios. The two portfolios can follow independent 15-minute schedules and are not required to charge or discharge in the same direction at the same time.

The use of a connection-level power envelope is particularly important when storage simultaneously participates in energy and ancillary services. The battery cannot use its full inverter capability for energy and then offer the same power again as reserve. The model therefore evaluates the remaining upward and downward flexibility around the active charging or discharging point.

When a battery is discharging, additional upward capability is limited by the unused discharge headroom, while downward capability may be obtained by reducing the existing discharge. When a battery is charging, upward capability can be provided by reducing the charging demand, and downward capability can be provided by increasing the charge. If the battery is idle, its provision of reserve is restricted by the operating-mode and minimum-activation conditions of the formulation. This operating-point-dependent treatment ensures that energy, mFRR, congestion management and FFR compete for the same physical inverter capability.

The capacity constraints are directional. For the TSO-connected battery aggregate, the upward power envelope jointly accounts for discharge, upward mFRR, upward TSO congestion management and upward FFR. The corresponding downward envelope jointly accounts for charging, downward mFRR, downward TSO congestion management and downward FFR. For the DSO-connected aggregate, the upward and downward envelopes combine its operating point with DSO congestion management and DSO-level FFR. Balancing energy is not added a second time to these envelopes because it is already embedded in the resulting charging or discharging position through the Day-Ahead Market linkage.

This formulation prevents the double counting of storage flexibility across products. A battery cannot, for example, be scheduled at its maximum discharge level and simultaneously offer its full power capacity as upward mFRR and FFR. The accepted service portfolio must remain physically deliverable from the final operating point.

Intertemporal energy consistency is represented through a daily relation between charged and discharged energy. For each aggregate, total discharged energy is constrained to correspond to 84% of total charged energy over the optimisation horizon. This relationship represents the aggregate round-trip conversion losses and prevents the model from using storage as a net source of energy over the day. The relation is imposed separately for the TSO- and DSO-connected portfolios.

The present storage representation does not track an explicit state-of-charge trajectory for every 15-minute period. Instead, energy consistency is enforced at daily level through the charged-to-discharged energy relation, while power feasibility is enforced in every Market Time Unit. This is appropriate for the current aggregate case-study representation, where detailed initial state of charge, energy capacity, degradation and individual battery duration data are not available.

The implication is that the formulation captures power availability and daily energy neutrality but does not explicitly test whether a particular sequence of charging and discharging would violate an intermediate state-of-charge limit. For applications requiring detailed battery cycling, the formulation can be extended with interval-by-interval state-of-charge tracking, minimum and maximum energy content, charging and discharging efficiencies, terminal-energy conditions and cycle-degradation costs. The balancing-requirement methodology itself recognises the absence of explicit state-of-charge information as one of the limitations of the available data.

2.4.3.3 Product eligibility of TSO- and DSO-connected storage

Storage eligibility is differentiated by connection level. In the current configuration, the TSO-connected battery aggregate can participate in upward and downward balancing energy, upward and downward mFRR, TSO congestion management and FFR. The DSO-connected battery aggregate can participate in balancing energy, DSO congestion management and FFR. It is excluded from TSO mFRR and TSO congestion-management provision.

This differentiation is not merely a market-design convention. It ensures that flexibility procured to solve a distribution-level problem is associated with a distribution-connected portfolio, while TSO services are allocated to resources considered deliverable at transmission-system level. Cross-level service variables are disabled, so the TSO aggregate cannot provide DSO congestion management and the DSO aggregate cannot provide TSO congestion management. Separate FFR variables are also used for the two connection levels, preventing the same battery capacity from being credited simultaneously at both levels.

In the calibrated case-study configuration, battery provision of FCR and aFRR is disabled. This is an explicit eligibility assumption rather than a general statement that batteries cannot technically provide these products. The purpose is to preserve the service-participation rules selected for the examined scenario and to avoid introducing battery FCR or aFRR quantities for which no corresponding market or calibration basis has been provided. The formulation can enable these products in a future scenario by activating the relevant bid variables and including them in the shared storage power envelope.

TSO-connected storage participation in mFRR may also be bounded as a proportion of the gross or residual mFRR requirement, depending on the scenario. This allows the model to assess material battery participation without allowing the entire reserve requirement to be concentrated in a single aggregated storage portfolio. Congestion-management provision may use a larger part of the available battery envelope, provided that the combined energy and service position remains within the physical power limit.

FFR is assigned principally to storage because its fast bidirectional response is well suited to the prospective high-renewable operating conditions represented in the 2030 scenario. Upward FFR is delivered through increased net injection or reduced charging, while downward FFR is delivered through increased charging or reduced discharge. The FFR requirement is itself a planning proxy related to periods of high renewable penetration and does not replace a full dynamic frequency-stability study.

2.4.3.4 Demand-response and aggregated prosumer flexibility

Prosumer and demand-side flexibility are represented through an aggregated demand-response portfolio. The portfolio can describe a combination of industrial loads, commercial facilities, aggregated residential demand, controllable appliances, electric-vehicle charging, heat-pump operation or other flexible consumption. The model does not identify the individual devices behind the aggregate. Instead, the aggregator exposes a validated upward and downward flexibility envelope to the system operator.

Upward demand-side flexibility corresponds to a reduction in electricity consumption and is treated as an increase in net system injection. Downward flexibility corresponds to an increase in consumption or a rebound following an earlier reduction and is treated as a decrease in net injection. Separate variables and availability limits are used for the two directions, avoiding the assumption that the same quantity of flexible demand is automatically available for both load reduction and load increase.

Demand-response availability is time dependent. The current case study uses a predefined stepped availability profile over selected operating windows, with zero availability outside those periods. This reflects the fact that aggregated consumers cannot normally be activated continuously over the entire day. The available capacity may increase or decrease between successive 15-minute intervals according to the assumed availability of industrial or aggregated loads.

The upward and downward operating modes of the demand-response portfolio are mutually exclusive. The aggregate cannot simultaneously reduce and increase demand in the same Market Time

Unit. An active portfolio must also operate above the minimum accepted quantity, thereby avoiding nominal activations that have no meaningful system effect.

The reserve stack assigned to demand response is constrained by the active operating level of the portfolio. The model cannot allocate mFRR and congestion-management quantities that exceed the demand reduction or demand increase that is physically available in that interval. This links the market award to an explicit operating envelope rather than treating the demand-response bid as unconstrained capacity.

In the current calibrated configuration, the demand-response portfolio is eligible for upward and downward mFRR and TSO congestion management. Upward provision is associated with load reduction, while downward provision is associated with controllable load increase or rebound. Direct balancing-energy provision, FCR and aFRR are disabled for demand response in this configuration. This eligibility matrix can be modified in alternative scenarios, but the present implementation deliberately limits demand response to products for which the assumed response time and operating representation are considered appropriate.

The current aggregate demand-response representation does not impose a detailed device-level minimum activation duration. The smallest activation that can be represented is one 15-minute Market Time Unit. The binary operating mode may change at an interval boundary, provided that the time-dependent availability and power limits remain satisfied.

Similarly, an explicit multi-period recovery trajectory is not imposed. Recovery is approximated through the separate downward flexibility channel representing load increase or rebound and through the exogenous availability envelope. The model therefore does not require that every megawatt-hour of curtailed demand be recovered at a particular later interval.

This is an appropriate simplification for a system-level balancing study but should be recognised when interpreting the results. Where detailed prosumer data become available, the model can be extended with minimum activation duration, maximum continuous activation, recovery delay, rebound-energy requirements, cumulative daily activation limits and comfort or process constraints. For electric vehicles, these could include connection windows, charging-energy requirements and departure state of charge. For thermostatically controlled loads, they could include thermal-state and comfort bounds.

2.4.3.5 Integration of prosumer constraints through the aggregator

The aggregate representation assumes that the flexibility offer submitted to the balancing model is internally feasible. Device-level constraints such as household comfort, production-process continuity, EV mobility requirements, appliance operating cycles and customer opt-out decisions are therefore expected to be reflected in the aggregate availability profile before market clearing.

Under this interpretation, the system-level model does not determine which individual consumer is activated. It determines the total amount of flexibility accepted from the aggregator. The aggregator is responsible for distributing this activation among its portfolio while respecting internal contractual and technical restrictions.

This separation is important for privacy and scalability. The system operator does not require detailed household-level data, while the aggregator does not need to expose commercially or personally sensitive information. At the same time, the aggregate capacity submitted to the market must be conservative enough to remain deliverable after accounting for internal uncertainty, non-response and rebound.

The current model treats the submitted flexibility envelope deterministically. Availability, operating limits and bid quantities are known for each 15-minute interval. Forecast uncertainty in prosumer availability or activation performance is not represented explicitly. A future stochastic or robust extension could derate the aggregate offer, introduce non-delivery scenarios or include reserve margins that reflect uncertainty in customer participation.

2.4.3.6 Fixed pumping-resource participation

Pumping resources are represented separately from the aggregated battery portfolios. Their pumping schedules can enter the system energy balance as fixed downward actions or dispatchable-load quantities. This treatment reflects the operational distinction between battery storage, which is co-optimised as a flexible aggregate, and observed pumped-storage schedules that may need to be reproduced from validated ISP results.

This treatment preserves the observed schedule, prevents the optimiser from reallocating an already validated pumping contribution and avoids double procurement. It also provides a general mechanism for incorporating other externally determined DER schedules where detailed endogenous modelling is either unnecessary or unsupported by the available data.

2.4.3.7 Integration with system-level balances

The accepted DER and prosumer bids are fully integrated into the system-level balancing constraints. Battery balancing energy and demand-side flexibility contribute to the same upward and downward system balance as conventional generation. Their reserve quantities enter the corresponding service-requirement constraints and are evaluated together with thermal and hydroelectric provision.

The contribution of each aggregate is assigned to a system and connection level. TSO-connected flexibility enters the TSO balancing and congestion-management layers, while distribution-connected flexibility is used for DSO congestion management and the corresponding FFR representation. This mapping provides a simplified form of locational deliverability without requiring detailed individual feeder models.

Every accepted DER service must be consistent with the operating position of the resource. Storage reserve is limited by the remaining charging or discharging headroom. Demand-response reserve is limited by the active demand-reduction or demand-increase envelope. Fixed pumping contributions are deducted before the residual requirement is allocated. As a result, the model does not treat flexibility bids as independent quantities that can be added without considering their common physical source.

The resulting clearing is therefore jointly determined by system imbalance, reserve requirements, congestion-management needs, FFR requirements, conventional-unit constraints and DER flexibility. A battery, demand-response portfolio or pumping resource is selected only when its use contributes to the least-cost feasible solution of the complete balancing problem.

2.4.3.8 Market realism and validation

The model includes safeguards to improve the operational realism of DER participation. Accepted non-storage flexibility quantities are subject to a minimum threshold, and provider-diversification conditions may be applied to avoid excessive concentration of a service in one resource. Maximum provider shares can also be imposed so that a large, aggregated resource does not cover an unrealistically dominant part of a requirement when a broader provider pool is available.

The aggregated battery portfolios are naturally large relative to individual DER assets. Their connection-level separation, service-eligibility rules and shared power envelopes are therefore particularly important. These conditions prevent the aggregation from behaving as an unconstrained system-wide flexibility source.

After optimisation, the DER contributions are included in the same strict balance audits as conventional resources. The model checks the balancing-energy balance and every reserve, congestion-management and FFR requirement for every 15-minute interval. An output is rejected where a material balance residual or unmet requirement remains. This provides a transparent check that the reported DER flexibility is not merely scheduled in the objective but is correctly incorporated into the system-level service balances.

2.4.3.9 Scope and limitations of the current representation

The current approach is an aggregated system- and connection-level representation. It does not identify individual prosumers, distribution feeders, local voltage constraints or the physical position of every DER. Distribution-level deliverability is represented through the DSO-connected aggregate and the separate DSO congestion-management requirement rather than through explicit feeder power flows.

The model also does not currently include individual battery state-of-charge trajectories, battery degradation, device-level recovery constraints, consumer utility or comfort losses, uncertainty in prosumer response, or detailed aggregator portfolio-disaggregation decisions. These characteristics are assumed to be reflected in the exogenous aggregate flexibility envelope or are represented through simplified daily and interval-level limits.

These limitations do not prevent the model from evaluating the system value of aggregated flexibility. The formulation captures the principal interactions between market schedules, bidirectional operation, connection level, energy and reserve stacking, availability and aggregate energy consistency. It therefore provides a suitable representation for the balancing and TSO–DSO coordination analyses undertaken in Deliverable 7.2.

If more granular data becomes available, the same framework can be extended to multiple aggregators, zones or distribution nodes. Each portfolio could be assigned a node-specific availability envelope, energy budget, response time, recovery condition and bid curve. Explicit feeder limits, distribution sensitivity factors or voltage constraints could then be introduced so that DER dispatch is validated not only at system level but also against local network conditions.

2.4.4 TSO–DSO Coordination Logic and Constraints

TSO–DSO coordination is implemented through a single-level, constraint-based co-optimisation. It is not formulated as a bilevel problem and does not require an iterative exchange between separate TSO and DSO optimisation models. System-wide balancing and reserve requirements are cleared together with separate TSO- and DSO-level congestion-management requirements within the same scheduling process.

Each flexibility portfolio is assigned a connection level and a corresponding service-eligibility matrix. In the current configuration, the TSO-connected storage aggregate can provide balancing energy, mFRR, TSO congestion management and FFR, whereas the DSO-connected aggregate can provide balancing energy, DSO congestion management and DSO-level FFR. Cross-level service variables are disabled, preventing a resource from being credited simultaneously as TSO- and DSO-deliverable flexibility. The same physical power capacity cannot therefore be counted twice across global and local services.

Local DSO obligations are treated as binding requirements. The capacity assigned to DSO congestion management or local FFR reduces the remaining flexibility of the distribution-connected portfolio. In a future configuration where distribution-connected resources are permitted to provide TSO reserves, only the capacity remaining after satisfaction of local DSO requirements and network-security limits would be made available to the TSO.

The DSO network process is based on a static grid representation derived from operational information and anonymised GIS exports. Transformer and line capacities, together with the adopted voltage operating band, are used to determine whether a proposed DER activation is locally feasible. The resulting local flexibility limits or DSO congestion requirements are transferred to the balancing model as exogenous constraints. The current coupling does not solve a simultaneous AC distribution power flow inside the unit-commitment problem.

At transmission level, detailed PTDFs, contingency-specific line limits and complete nodal data are not available in the present dataset. TSO congestion management is therefore represented through an aggregate transmission-stress requirement, while DSO congestion management reflects distribution-side residual-load and renewable-surplus conditions. The approach is consequently grid-aware but not a full nodal TSO–DSO security-constrained formulation.

Joint-dispatch priorities are handled through constraints rather than an arbitrary operator hierarchy. Local network security and resource eligibility are enforced first; system and local service balances must then be satisfied exactly; validated fixed schedules are credited before the residual requirement is cleared; and the remaining technically feasible flexibility is allocated according to total system cost. In the integrated congestion-management scenario, overlapping TSO and DSO needs may be consolidated to avoid double counting, while maintaining the local DSO feasibility conditions.

2.4.5 Technical Assumptions and Input Parameters

The model is parameterised through dedicated input workbooks containing unit characteristics, market schedules, reserve requirements, system imbalance, flexibility availability, storage data and balancing-market offers. The principal assumptions are summarised below.

Table 2. Balancing Market Digital Twin Technical Assumptions

Input category	Assumption and parameterisation
Temporal scope	Deterministic one-day horizon with 96 consecutive 15-minute Market Time Units. Initial operating conditions are provided for the period immediately preceding the optimisation horizon.
Demand and RES	Demand and renewable-generation profiles are deterministic. Historical profiles or scaled stress scenarios are used. Weather is not modelled directly; its effects are embedded in the selected demand and RES availability profiles.

Reserve requirements	FCR, aFRR and mFRR requirements are provided per direction, system and 15-minute interval. TSO congestion management, DSO congestion management and FFR are supplied through pre-processed requirement files or the corresponding case-study proxy methodology.
Generation units	Inputs include technical minimum and maximum output, AGC operating limits, FCR/aFRR/spinning and non-spinning mFRR capabilities, ramp-up and ramp-down rates, minimum up and down times, start-up and shutdown costs, initial status and Day-Ahead Market schedule.
Economic inputs	Upward and downward balancing-energy prices and reserve-capacity offer prices are specified by unit and Market Time Unit. Start-up and shutdown costs are included separately. Strategic bidding and endogenous offer formation are not represented.
Storage systems	Storage is represented through TSO- and DSO-connected aggregates. The current case-study envelope is 1,730 MW, divided into 1,211 MW at TSO level and 519 MW at DSO level. Daily discharged energy is assumed to equal 84% of charged energy. No detailed intermediate state-of-charge trajectory is currently imposed.
DER and demand response	DER capacities and availability profiles are assumed known. Demand-response availability is deterministic and time dependent; the current industrial-flexibility profile uses availability levels of 100–150 MW during selected 15-minute windows and zero availability outside them.
DSO network model	The distribution model is static and based on operational data and anonymised GIS exports. Transformer and line capacities follow internal technical documentation. The adopted voltage operating range is ±10% around nominal. Loads may represent historical or scaled stress conditions, while DER availability is defined through deterministic profiles.
TSO network representation	Explicit transmission PTDFs, nodal line limits and contingency data are not included in the current balancing dataset. TSO congestion is represented through aggregate requirements rather than explicit transmission power-flow constraints.
Uncertainty	No stochastic demand, RES or weather forecast scenarios are currently integrated. All simulations use fixed input profiles. External forecasting modules may be incorporated in future versions.
Confidentiality	Sensitive network topology, asset identifiers and GIS information are anonymised before use in Deliverable 7.2.

The balancing layer and the static DSO assessment may use different native temporal resolutions: the balancing optimisation operates at 15-minute resolution, whereas the distribution-grid assessment may be performed for hourly or selected stress snapshots. Their interface is based on pre-processed local limits and congestion requirements rather than direct exchange of confidential network topology. Detailed PTDF-, DSF- or voltage-sensitivity-based coordination can be introduced when suitable transmission and distribution network datasets become available.

2.5 Scenario-Based Simulation and Results

Section 2.5 translates the Greek Demo architecture into operational evidence. Rather than assessing the individual tools in isolation, the scenarios are followed through the complete digital-twin chain: the Day-Ahead Market Simulator generates the market position; IPTO methodologies determine the corresponding 15-minute reserve requirements and projected system imbalances; the Balancing Market Digital Twin allocates balancing energy and flexibility services; and the resulting schedules are examined by the transmission- and distribution-grid validation tools.

The analysis addresses three complementary questions. First, it evaluates whether the projected 2030 market configuration improves DER participation, market-clearing outcomes and social welfare. Second, it examines whether the balancing system can cover energy imbalances, FCR, aFRR, mFRR, congestion-management and FFR requirements under contrasting seasonal conditions. Third, it tests whether economically cleared schedules remain physically deliverable when applied to the transmission and distribution grids.

The interpretation is based on a common set of indicators covering market prices, cleared DER volumes, social welfare, balancing-energy activation, reserve sufficiency, conventional generation and commitment, battery utilisation, demand-response activation, service-provider concentration and network violations. Energy production and activation are reported separately from time-aggregated reserve-capacity volumes, since maintaining one megawatt of reserve over several intervals is not equivalent to delivering the same quantity of energy. The section also distinguishes controlled counterfactual comparisons from broader comparisons between complete system configurations, thereby avoiding causal conclusions where the underlying requirements are not fully harmonised.

2.5.1 Description of Scenario Design

The scenario design combines three layers: a common transformation of the Greek electricity system toward 2030, four representative seasonal operating conditions, and alternative flexibility and TSO–DSO coordination configurations. This layered structure allows the analysis to separate the effects of long-term system transformation from those of short-term demand, RES availability and flexibility deployment.

2.5.1.1 Projection of electricity market and power system for 2030

The ongoing transition towards a low-carbon electricity system, driven by decarbonisation objectives and evolving energy policies, is fundamentally transforming the European energy landscape. The gradual phase-out of conventional generation, increasing renewable energy penetration, deployment of emerging flexibility technologies, and expansion of transmission infrastructure constitute the key pillars of this transition. Together, these developments introduce significant uncertainty regarding future power system conditions and electricity market operation, while challenging existing market arrangements. In this context, national-scale long-term modeling and simulation become essential for representing future system conditions, evaluating their impact on market outcomes, and supporting strategic electricity market planning.

Against this background, a detailed 2030 energy scenario is developed to evaluate the impact of the projected evolution of the Greek electricity system on the day-ahead and balancing market. The scenario combines national policy targets, system-development assumptions, and strategic transmission infrastructure updates into a consistent representation of the projected 2030 Greek electricity system, providing the foundation for assessing the Greek day-ahead market under projected 2030 system conditions.

The evolution of the Greek day-ahead and balancing markets toward 2030 is represented by extending the current market framework in line with national planning assumptions. The principal sources are the revised Greek NECP and the HETS Ten-Year Network Development Plan 2024–2033, which describe generation-mix restructuring, higher RES penetration, storage and demand-response integration, the Attica–Crete HVDC interconnection and changes in transmission capacity [21], [22]. Technology-specific order types, including circular block orders for storage, are introduced through targeted modifications of historical orderbooks and network data.

For technologies already participating in the Greek electricity market, projected changes are implemented through a common scaling approach: Technology-specific scaling factors are applied to the submitted quantities (MW) of historical market orders, calculated as the ratio between the projected (2030) and baseline (2025) installed capacities. For synthetic assets and technologies not currently represented in the Greek day-ahead market (storage and demand response), synthetic market orders are generated on the bidding behaviour of comparable existing assets and technology-specific modeling assumptions. The technical characteristics of newly introduced assets are obtained from the Common Pilot Asset Registry. Accordingly, the projected market configuration is established through the following alterations:

1. Demand is scaled by an average factor of 1.20, based on projected 2030 annual electricity demand of 61.3 TWh [21] relative to the 2025 annual demand of 51.37 TWh [27].
2. RES generation is scaled by a factor of 1.83, based on the projected 2030 RES share of 75.7% of gross electricity consumption [21] relative to the 2025 RES production level of 25.3 TWh [27].
3. Removal of lignite-fired generation units, reflecting the complete phase-out of lignite generation.
4. Addition of 2,993 MW of net natural gas-fired generation capacity to the existing fleet of approximately 6.8 GW through synthetic market orders (curve and block orders) generated by replicating the orders of existing natural gas units, with submitted quantities scaled according to the net capacities of the newly introduced assets.
5. Addition of 1,699 MW of hydroelectric and pumped-storage capacity (919 MW hydroelectric and 780 MW pumped storage) to the existing fleets of 3,170 MW and 699 MW, respectively, through synthetic curve orders generated by replicating the orders of existing hydroelectric and pumped-storage units, with submitted quantities scaled according to the net capacities of the newly introduced assets.
6. Battery energy storage systems with 4,325 MW of net power capacity and 10,996 MWh of energy capacity are introduced through synthetic circular block orders [21]. Each storage asset is represented by a linked charging block and discharging block corresponding to one daily cycle. Charging orders cover 12:00–15:00 (MTUs 49–60) and discharging orders cover 20:00–22:00 (MTUs 77–88), with a minimum acceptance ratio of 100%. The submitted charging quantity is calculated as:

$$Q_{\text{Storage}} = \frac{X \times E_{\text{useful}}}{N_{\text{MTUs}}}$$

   where X is a predefined utilization factor of the available energy capacity (X=40%), $E_{\text{useful}}$is the useful energy capacity of the storage unit, and N_{MTUs} is the number of 60-minutes MTUs covered by the block. The submitted discharging quantity is calculated analogously, with an additional round-trip efficiency factor of 84% applied.

7. Demand-response participation totalling 3.1 GW of net capacity is represented through synthetic simple sell block orders [28]. Each asset submits one sell block for 20:00–23:00 (MTUs 77–92). The quantity is based on a 37% utilisation factor applied to an available capacity equal to 80% of licensed net capacity, and the minimum acceptance ratio is 70%.

$$Q_{DR} = X \times C_{DR}$$

   where X is a predefined utilization factor of the available demand response net capacity (X=37%), and C_{DR} is the available net capacity of the demand response asset, defined as 80% of its licensed net capacity. A minimum acceptance ratio (MAR) of 70% is assigned to each block order, requiring that an accepted order must clear at least 70% of its submitted quantity. The utilization factors X are selected such that comparable total submitted volumes are achieved for the synthetic participation of demand response and storage.

   A heuristic pricing methodology is employed to define storage and demand response submitted order prices based on market clearing prices (MCPs) obtained from the simulation of the historical Greek day-ahead market. The historical baseline market configuration is first generated by running the DAM Simulator without applying any of the projected scenario alterations. The resulting MCPs serve as the reference case for the pricing methodology:

   For the examined simulation period (p), the MCP range is calculated as:

$$range_p = MCP_{p,max} - MCP_{p,min}.$$

   Synthetic order prices are then assigned within this range according to

$$OrderPrice_p = MCP_{p,min} + Y \cdot range_p$$

   where Ytechnology-specific scaling coefficients that determine the relative position of the order prices within the observed MCP range. The Yvalues are selected based on the merit order observed in the baseline market simulation, such that the synthetic order prices are positioned to increase the probability of market acceptance. The coefficients are set to 60% for storage discharging orders, 25% for storage charging orders, and 55% for demand response orders.
8. Addition of two synthetic dispatchable RES assets located on the island of Crete, representing 78 MW of photovoltaic generation (PV) and 67 MW of wind generation, through synthetic stepwise curve sell orders. The submitted order quantities are determined for each simulation period using asset-specific generation profile time series provided by IPTO, while the submitted order prices are selected to broadly reflect the price ranges of orders submitted by existing assets of the corresponding technology (PV, wind).
9. The commercial operation of the Attica–Crete HVDC interconnection is incorporated into the 2030 market topology [22]. Crete demand and RES orders are converted from priority price-taking orders into stepwise curve orders, while conventional diesel generation is removed from ordinary market participation and retained only as emergency backup.
10. Cross-border capacities are adjusted in line with the projected 2030 interconnectivity of the HETS [21], [22]. Projected-to-current NTC ratios are applied to historical ATC values on coupled borders and to import and export order quantities on non-coupled borders where explicit network constraints are not represented.

For each delivery day of the simulation period, the DAM Simulator implements the 2030 market scenario by sequentially applying the above alteration functions (1-10) to the historical Greek DAM orderbook and network data, thereby constructing the corresponding projected 2030 Greek day-ahead market configuration.

2.5.1.2 Selected days and scenarios

In order to capture essential market dynamics, comprehensive simulations were performed over a wide range of days utilizing quarter-hourly data. High-fidelity electricity market simulations and power flows require representing both seasonal load variations and the intermittency of RES.

Indicative days were selected using a heuristic quadrant approach that pairs extreme and typical system load conditions with corresponding RES penetration levels. This targeted selection serves to clearly demonstrate the balancing market model performance and the power flow technical feasibility under the most contrasting and critical operational envelopes of the grid.

Based on the broader simulation database, the following four indicative days have been selected to map the core operational quadrants for detailed comparative analysis:

Table 3. Selected days and scenarios

Operational Scenario	Indicative Date	Seasonal & System characteristics	Selected Date
Low RES – Low Load	01/11/2025	Typical autumn day with low overall demand and low RES generation; establishes baseline thermal unit dispatch	01/11/2030
Low RES – High Load	21/01/2026	High-demand winter day with peak heating loads and low RES generation; tests system adequacy and the dispatch of conventional units	21/01/2030
High RES – Low Load	17/05/2026	Typical mid-seasonal spring day with mild temperatures and exceptionally high RES generation; crucial for evaluating over generation and curtailment mitigation	17/05/2030
High RES – High Load	06/07/2026	Peak summer day with high cooling demand aligned with maximum RES generation; represents the ideal scenario for testing peak-shaving and congestion management	06/07/2030

RES and load refer to the respective ISP projections based on the scaling factors defined in the previous subsection, as illustrated in Figure 10. Projected load and losses and RES profile for each simulation day.. These profiles are identical in the baseline and increased-flexibility cases; the key difference between the two scenarios is the expected installed capacity of flexible assets.

To thoroughly evaluate the impact of flexible resources on the balancing market results, two distinct simulation cases are described for each selected day:

1. Baseline case: Represents the projected 2030 generation mix without incorporating additional flexible assets.
2. Increased flexibility case: Integrates additional flexible assets into the generation mix to highlight their contribution toward mitigating grid stress, relieving congestion and improving overall market and system performance.

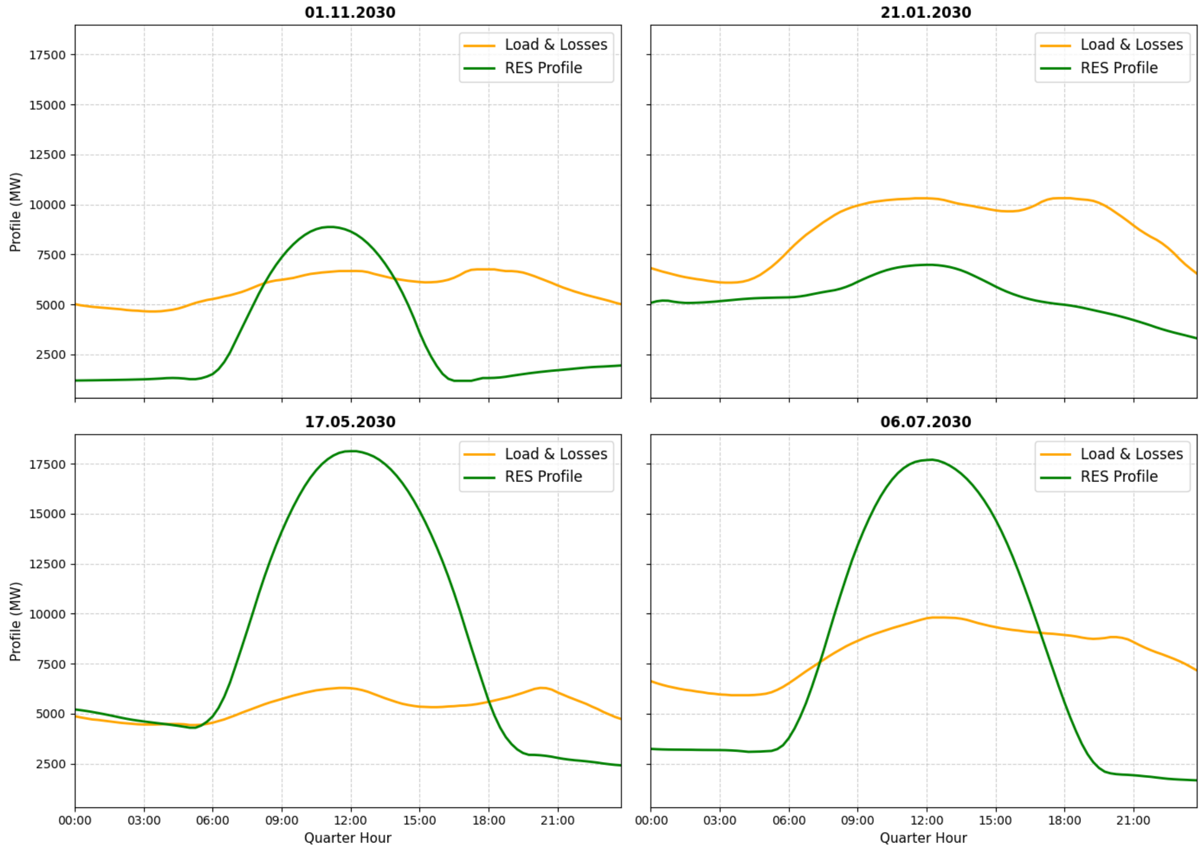


Figure 10. Projected load and losses and RES profile for each simulation day.

2.5.2 Evaluation of Different TSO–DSO Coordination Models

Two coordination configurations are evaluated. In the separated benchmark, TSO and DSO congestion-management requirements are procured independently and are therefore additive. In the coordinated configuration, only the simultaneous and directionally compatible component is consolidated; the integrated requirement never falls below the larger individual need and never exceeds their sum. The stronger operational need is therefore preserved while duplicated procurement is removed.

Coordination remains connection-aware. DSO-connected flexibility is first constrained by local voltage and equipment limits and by its service-eligibility matrix; only locally feasible capacity can support joint dispatch. The balancing optimiser then allocates the residual requirement across eligible resources according to total system cost, with validated fixed schedules credited before residual procurement.

For the analysed 96-period dataset, coordination reduces the additive upward congestion-management volume from 1,704.854 to 1,551.259 MWh (−9.01%) and the downward volume from 2,079.830 to 1,754.289 MWh (−15.65%). These values represent avoided duplication rather than relaxed security requirements and are interpreted together with DER utilisation, residual procurement and grid-feasibility outcomes later in this section.

2.5.3 Key Performance Indicators

The market-related KPIs compare the historical Greek day-ahead market configuration with the projected 2030 configuration for the four representative seasonal days defined in Section 2.5.1.2. The assessment examines the evolution of DER participation and its effect on cleared energy volumes and social welfare. Two KPIs are evaluated:

VI. Facilitating DER Transactions in the Day-Ahead Market (MWh) (Table 4): total cleared DAM energy from RES and emerging flexibility technologies under the historical and projected 2030 configurations. The indicator captures increased RES participation and the introduction of BESS, demand response and dispatchable RES in Crete through curve, simple-block and circular-block orders.

VII. Social Welfare Increase from DER Participation in the Day-Ahead Market (%) (Table 5): percentage change in total social welfare between the projected 2030 and historical market configurations.

$$KPI_{SW}(\%) = \frac{SW_{2030} - SW_{baseline}}{SW_{baseline}} \times 100$$

where $SW_{2030}$and $SW_{baseline}$denote the total social welfare under the projected 2030 and historical market configurations, respectively. Total social welfare is defined as the sum of producer and consumer surpluses:

$$\mathrm{SW} = \mathrm{PS} + \mathrm{CS}$$

where producer surplus (PS) represents the economic benefit obtained by producers from selling electricity at a market clearing price higher than the minimum price they are willing to accept, while consumer surplus (CS) represents the economic benefit obtained by consumers from purchasing electricity at a market clearing price lower than the maximum price they are willing to pay.

Table 4. KPI I: Facilitating DER Transactions in the Day-Ahead Market (MWh).

Delivery date	Baseline (MWh)	2030 (MWh)
01/11/2025	48,246.228	97,491.036
21/01/2026	75,327.997	139,538.246
17/05/2026	97,628.448	162,975.974
06/07/2026	114,055.803	191,021.599

As shown in Table 4, the projected 2030 configuration increases cleared DER transactions under all representative operating conditions. The largest absolute increase occurs in the high-load/high-RES case on 6 July, at approximately 77 GWh, while the smallest occurs in the low-load/low-RES case on 1 November, at approximately 49 GWh. The winter high-load/low-RES case and the spring low-load/high-RES case show comparable additional volumes of approximately 64–65 GWh.

In relative terms, the 1 November historical baseline has the lowest cleared DER volume and therefore records the largest increase under the 2030 configuration, at 102.1%, as illustrated in Figure 11. The smallest relative increase is observed on 17 May (66.9%), closely followed by 6 July (67.5%), because the historical baselines for those days already contain comparatively high renewable participation.

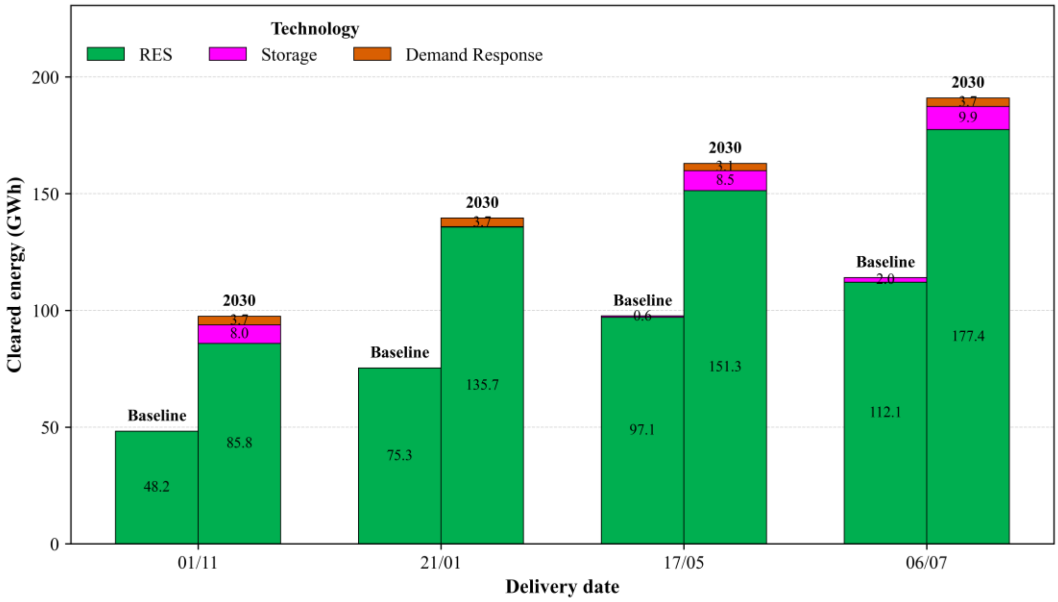


Figure 11. KPI I – Total daily cleared DER transactions by technology under the baseline and projected 2030 Greek day-ahead market configurations for the representative seasonal days.

Table 5 shows that total social welfare increases across all four representative days. In absolute terms, the high-demand summer and winter days produce the largest total welfare values because of their larger cleared electricity volumes.

Table 5. KPI II: Social Welfare Increase from DER Participation in the Day-Ahead Market (%).

Delivery date	Baseline Social Welfare (€)	2030 Social Welfare (€)	Increase (%)
01/11/2025	143,781,720.34	177,424,382.65	**23.40**
21/01/2026	229,675,319.01	280,460,029.80	**22.11**
17/05/2026	146,538,969.85	186,639,590.64	**27.37**
06/07/2026	212,781,689.45	269,038,356.87	**26.44**

Conversely, when examining the relative percentage increase (%), the spring day (17/05/2026) exhibits the highest relative gain (+27.37%), closely followed by the summer day (06/07/2026) at +26.44%. The spring day benefits from the optimal alignment of strong solar RES output and moderate demand, allowing storage and DR to completely eliminate high-cost peak hours. Interestingly, the summer day combines both high absolute volume and a strong percentage increase (+26.44%), demonstrating that DER flexibility (battery storage peak-shaving and active DR load-shifting) provides maximum economic value when high-RES generation coincides with heavy cooling demand. The autumn (+23.40%) and winter (+22.11%) days also display solid welfare gains, albeit slightly lower in relative terms due to higher baseline reliance on conventional thermal dispatch during low-solar periods.

Figure 12 decomposes the social-welfare change into Consumer Surplus (CS) and Producer Surplus (PS). Consumer Surplus is the dominant contributor on all four days, reaching gains of €37.80 million in winter, €37.18 million in summer, €26.59 million in spring and €26.32 million in autumn. Higher daytime RES output lowers prices, while storage and demand response reduce exposure to high-price evening periods.

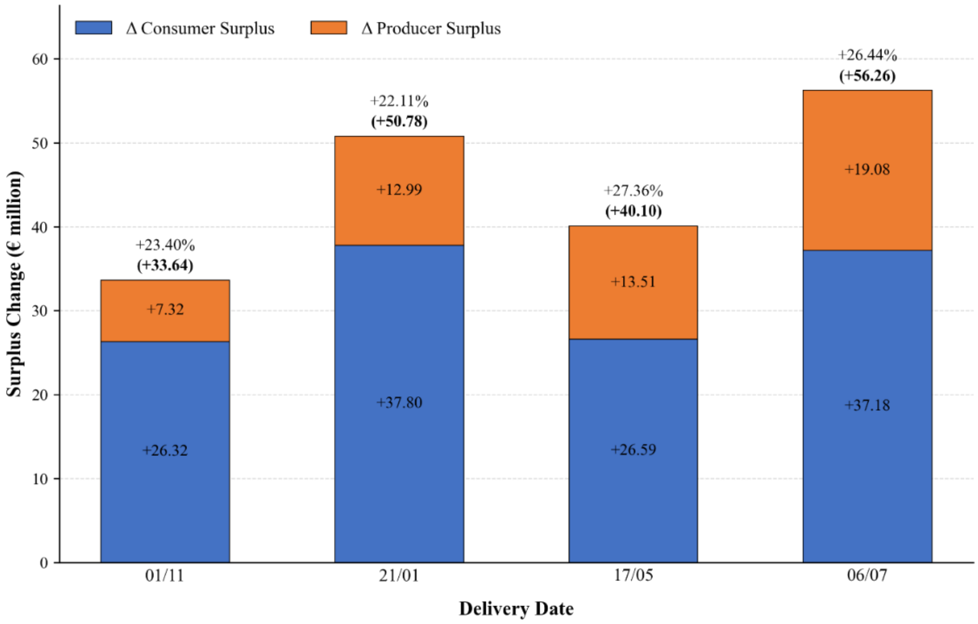


Figure 12. KPI II – Decomposition of the 2030 social-welfare change (ΔSW) into consumer- and producer-surplus gains for the representative seasonal days.

Producer Surplus (PS) records smaller gains, with the highest increase in summer (€19.08 million) and the lowest in autumn (€7.32 million). Conventional generators operate for fewer hours as RES participation grows, while renewable generators face lower margins during periods of high simultaneous output.

Overall, the 2030 scenario simulation demonstrates that the integration of DERs constitutes an effective mechanism for increasing total social welfare. However, the resulting economic benefits are distributed asymmetrically, with the largest share of the welfare gains captured by electricity consumers, as low market clearing prices transfer the bulk of the economic surplus from energy producers to consumers.

An additional DAM run defines the 2030 baseline used for the remaining pilot KPIs. This configuration applies the 2030 scenario without alterations 6–8 in Section 2.5.1.1, namely the additional participation of storage, demand response and dispatchable RES in Crete.

2.5.4 Results from Demand and RES Variability Stress Tests

This section evaluates the four representative operating days as deterministic demand-and-RES stress cases rather than stochastic forecast-error experiments. The profiles span low and high demand combined with low and high RES conditions and are examined through historical-versus-2030 DAM comparisons, reserve and imbalance calculations, reduced- versus full-flexibility BM configurations, and transmission- and distribution-grid validation. Explicit probabilistic forecast uncertainty remains outside the present scope.

2.5.4.1 Results of the Greek Day-Ahead Market simulation

The Greek day-ahead market is simulated under historical and projected 2030 conditions for the four representative days defined in Section 2.5.1.2. Two market configurations are considered: the unaltered historical baseline and the 2030 scenario described in Section 2.5.1.1. The corresponding market outcomes are compared for 1 November 2025, 21 January 2026, 17 May 2026 and 6 July 2026.

The DAM Simulator is first validated against the actual Greek day-ahead market clearing prices. Figure 13 presents the difference between actual and simulated MCPs for each MTU of the four representative days and shows close agreement across the validation period.

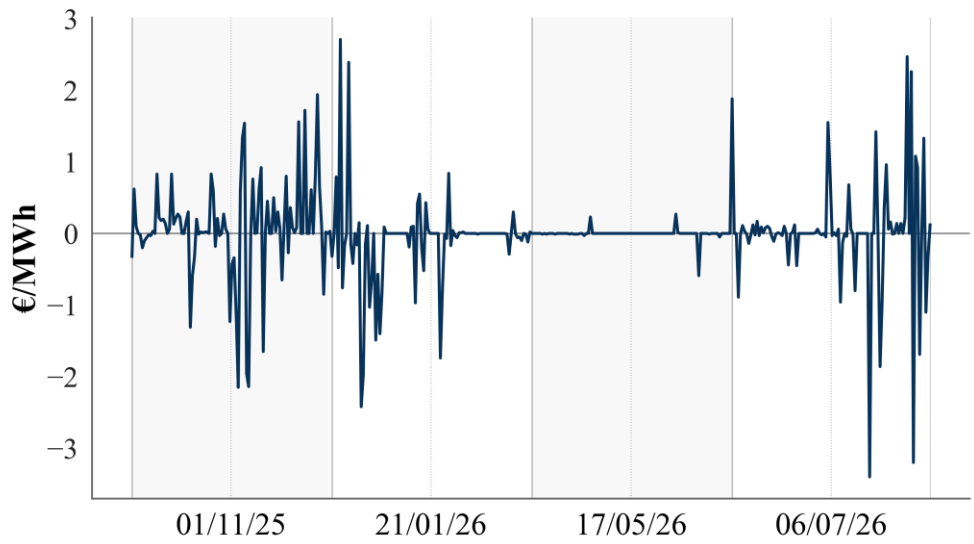


Figure 13. Greek MCP validation error over the representative delivery days.

Table 6 reports the MCP validation metrics. Mean error is close to zero for every day, while mean absolute error and RMSE remain low. The largest errors occur on 6 July, with an RMSE of 0.781 €/MWh and maximum absolute error of 3.40 €/MWh; the smallest occur on 17 May, with corresponding values of 0.071 €/MWh and 0.59 €/MWh.

Table 6. MCP validation metrics (€/MWh) of the DAM Simulator under the baseline scenario for the representative days.

Delivery Date	Mean Error	Mean Absolute Error	Root Mean Square Error	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

Table 7 summarises the daily MCP statistics under the historical and 2030 market configurations. Figure 14 presents the corresponding MCP time series, while Figures 15–18 compare cleared demand- and supply-side volumes by technology.

Under the 2030 configuration, average MCPs decrease on all representative days, from a 12.7% reduction in autumn to 55.8% in spring; the winter and summer reductions are 14.3% and 29.3%, respectively. Figure 14 shows that autumn and winter retain broadly similar daily shapes at lower price levels, whereas spring and summer exhibit longer low-price periods and stronger intraday fluctuations.

Table 7. Daily MCP characteristics (€/MWh) by market scenario.

Delivery date	Scenario	Min	Max	Mean	Std	CV (%)
01/11/2025	*baseline*	14.38	198.97	85.61	41.90	48.94
	2030	0.00	195.37	74.70	40.49	54.20
21/01/2026	*baseline*	114.16	219.71	146.33	23.24	15.88
	2030	84.03	233.16	125.44	32.85	26.19
17/05/2026	*baseline*	-1.01	168.83	75.21	65.93	87.66
	2030	-50.00	168.83	33.21	71.43	215.07
06/07/2026	*baseline*	12.78	209.86	110.13	48.58	44.11
	2030	-0.01	186.90	77.88	66.34	85.19

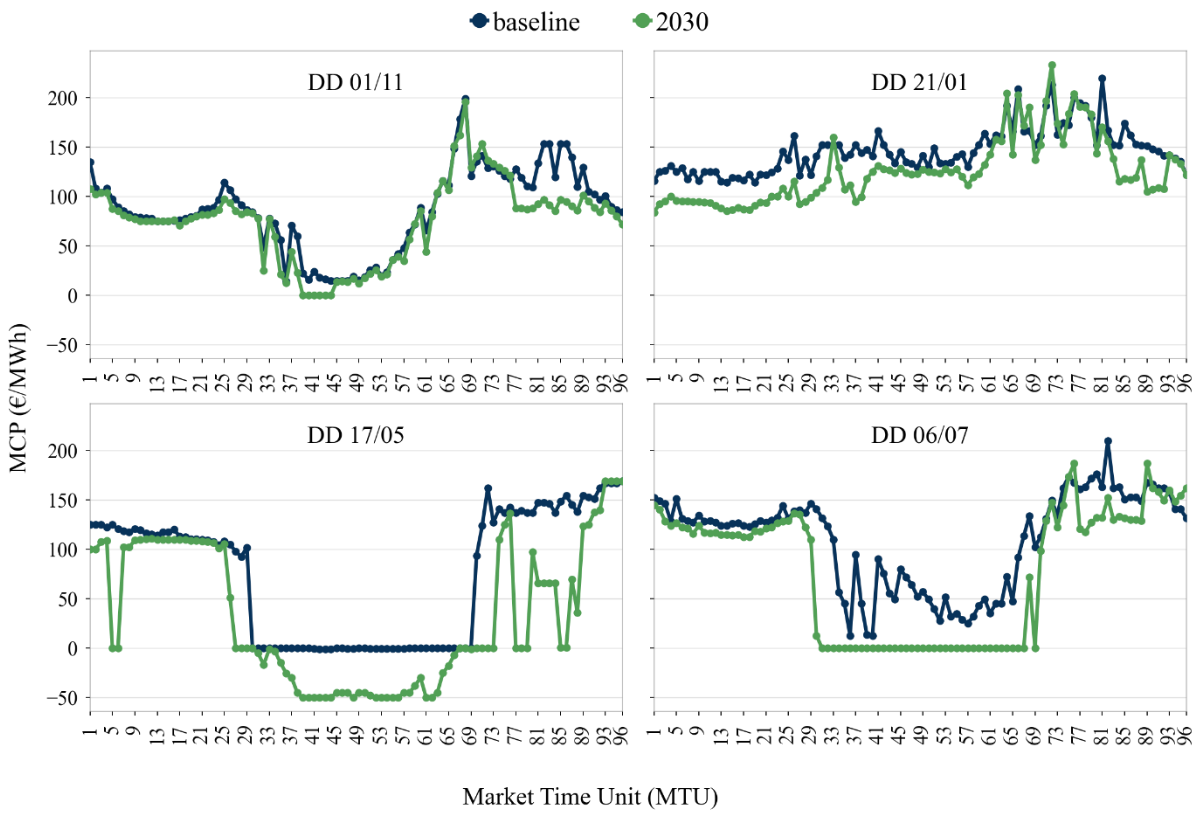
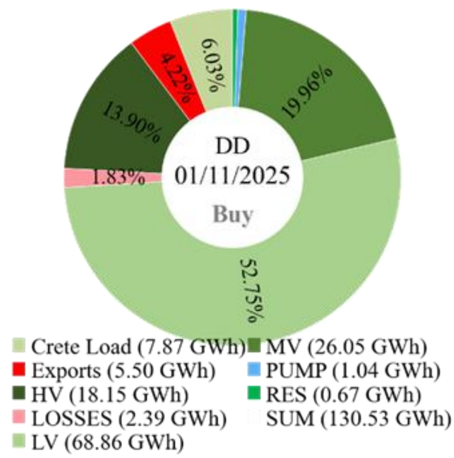


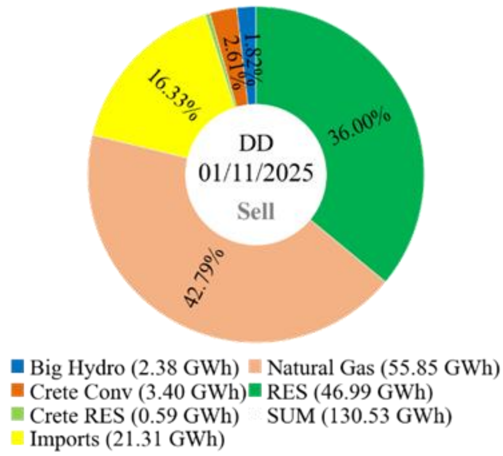
Figure 14. MCP time series under the baseline and 2030 scenarios.

During autumn, the MCP profile remains largely unchanged. Absolute price dispersion is also nearly identical (41.90 vs. 40.49 €/MWh), whereas the higher coefficient of variation (48.94% vs. 54.20%) indicates that similar price fluctuations occur around a lower average MCP.

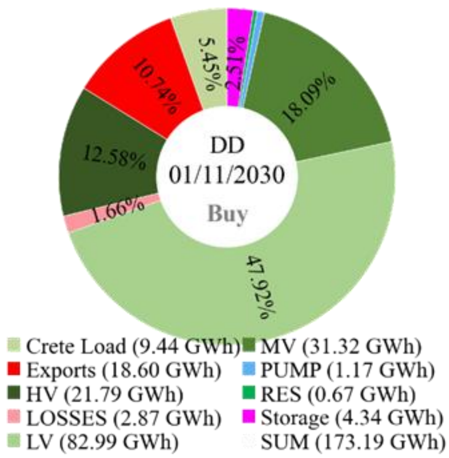
Compared with autumn, the winter case shows a stronger daytime price reduction and more pronounced evening oscillations, as illustrated in Figure 14. The standard deviation increases from 23.24 to 32.85 €/MWh and the coefficient of variation from 15.88% to 26.19%.



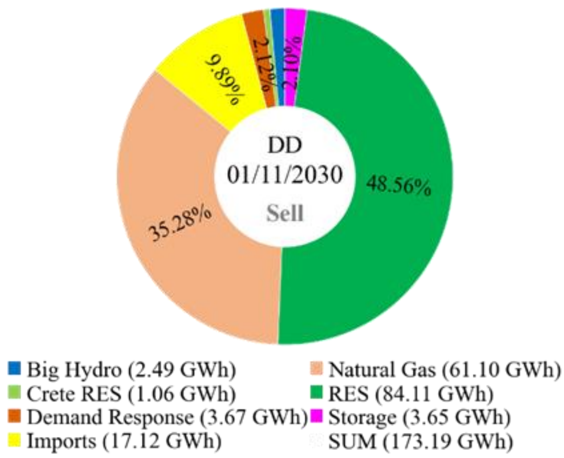
(a) *baseline scenario* - Buy



(b) *baseline scenario* - Sell



(c) 2030 scenario - Buy



(d) 2030 scenario - Sell

Figure 15. DD 01/11: Total daily cleared demand- and supply-side volumes by technology under the (a)–(b) baseline and (c)–(d) 2030 scenarios.

The strongest changes in market behavior are observed during spring. Increased renewable generation introduces prolonged low- and negative-price periods together with sharp evening price spikes. This behaviour is reflected by a modest increase in the standard deviation (65.93 to 71.43 €/MWh), whereas the coefficient of variation rises markedly from 87.66% to 215.07%, reflecting the higher variability of renewable generation under relatively low demand conditions.

During summer, similar market behavior is observed, although the higher seasonal demand partially moderates the price-depressing effect of increased renewable generation. Accordingly, the standard deviation increases from 48.58 to 66.34 €/MWh and the coefficient of variation from 44.11% to 85.19%, indicating stronger absolute and relative price dispersion than under the baseline market. This reflects a more polarized MCP profile, where prolonged low-price periods persist during hours of high renewable generation, whereas higher evening demand limits the price reduction by requiring greater participation of conventional generation.

The impact of the projected 2030 Greek energy landscape on the market is further analysed through a comparison of the cleared supply and demand mixes under the baseline and 2030 scenarios.

The autumn case is shown in Figure 15. RES penetration rises from 36.0% to 48.56%, while storage and demand response account for 4.61% and 2.12% of cleared volume. Although natural-gas output increases in absolute terms, its share falls by 7.51 percentage points. Conventional generation in Crete is phased out following commercial operation of the Attica–Crete interconnection; import dependence declines and exports increase alongside RES output.

The winter case is shown in Figure 16. RES penetration increases from 31.61% to 45.48%, but high demand still requires substantial dispatchable generation. Natural gas becomes the dominant conventional source and replaces lignite, while both imports and exports increase relative to the historical baseline.

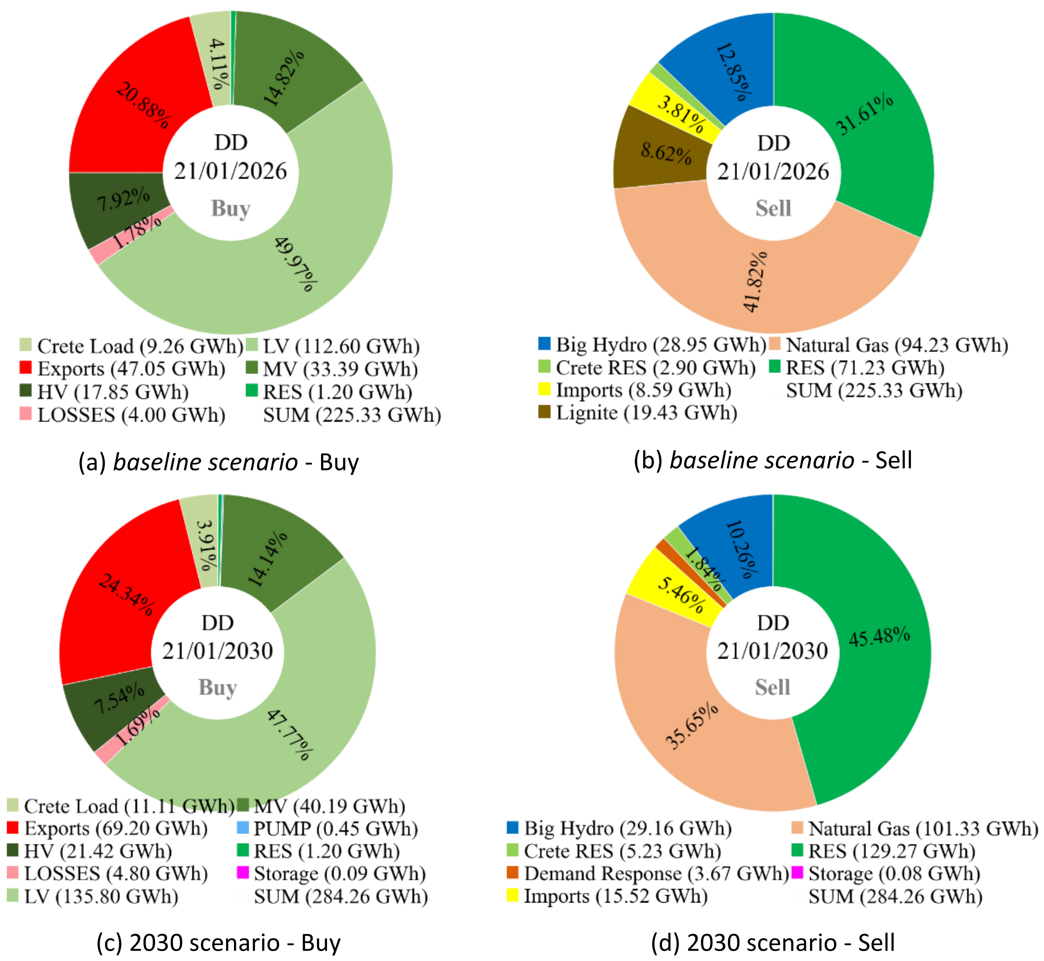
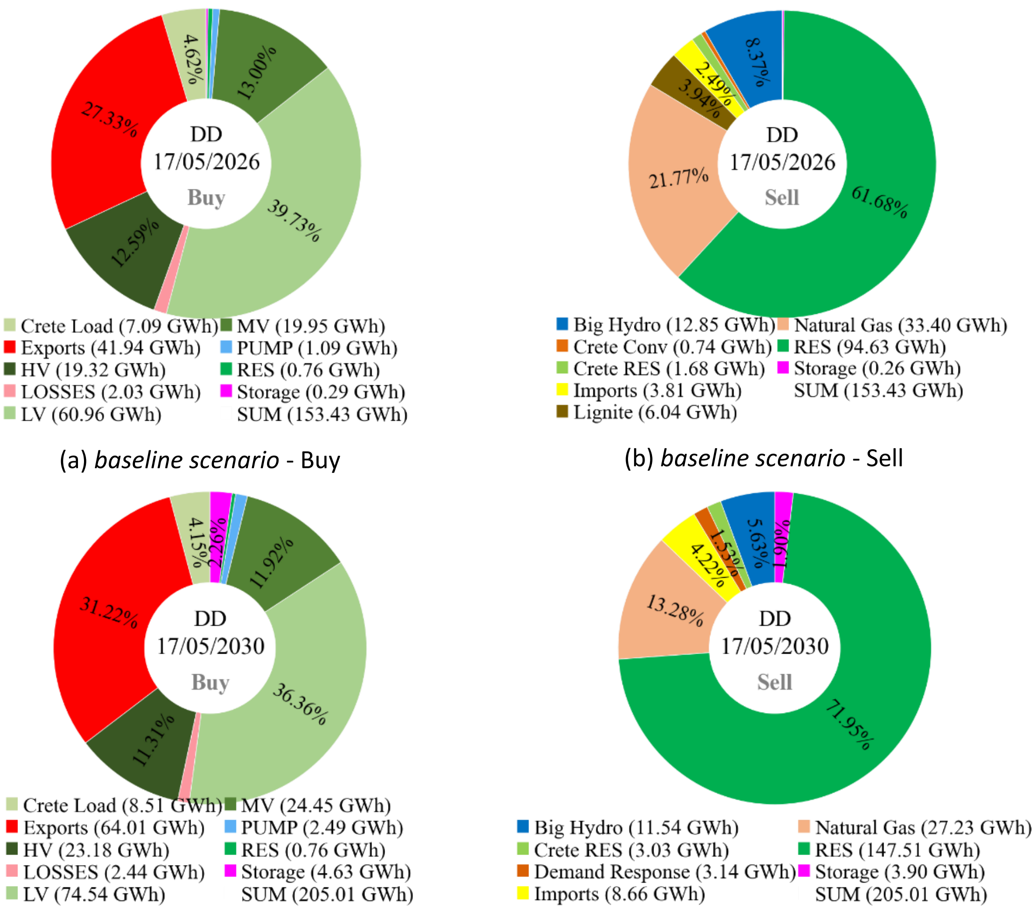


Figure 16. DD 21/01: Total daily cleared demand- and supply-side volumes by technology under the (a)–(b) baseline and (c)–(d) 2030 scenarios.

The spring case is shown in Figure 17. Low seasonal demand and high renewable availability increase the RES share of cleared supply from 61.68% to 71.95%, while the natural-gas share falls from 21.77% to 13.28%. Storage and demand response provide additional flexibility, and higher renewable output substantially increases exports.



(a) *baseline scenario* - Buy

(b) *baseline scenario* - Sell

(c) 2030 scenario - Buy

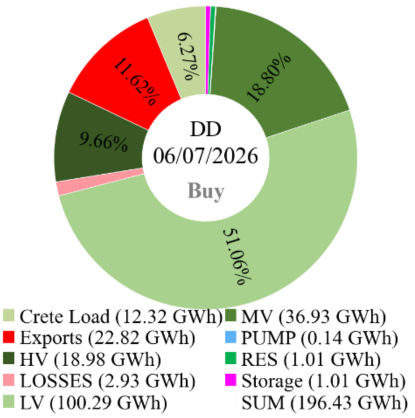
(d) 2030 scenario - Sell

Figure 17. DD 17/05: Total daily cleared demand- and supply-side volumes by technology under the (a)–(b) baseline and (c)–(d) 2030 scenarios.

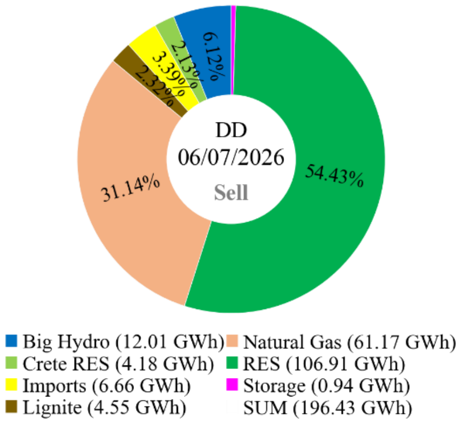
The summer case is shown in Figure 18. High cooling demand coincides with strong renewable output, with RES providing 63.34% of cleared supply. Storage reaches its highest day-ahead charging and discharging volumes among the four representative days, absorbing midday solar generation and shifting energy toward the evening peak. The natural-gas share and import dependence both decline, while exports increase.

Overall, the comparison across all seasons reveals four common structural patterns in the projected 2030 market configuration. RES consistently dominate the cleared supply mix, becoming the primary generation source. Conventional generation is progressively reduced following the complete phase-out of lignite and Crete conventional diesel generation, while Natural Gas remains essential for ensuring system adequacy. Storage and demand response emerge as active flexibility providers in the market, supporting the integration of higher shares of renewable generation through energy shifting and flexible demand reductions. Finally, cross-border export activity strengthens substantially, while import activity remains relatively limited under most operating conditions.

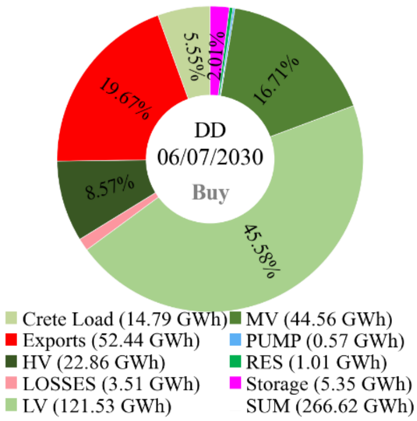
Collectively, these findings demonstrate that the proposed 2030 scenario successfully captures the expected structural evolution of the Greek day-ahead market towards a more flexible and renewable-driven market structure, characterized by lower market clearing prices, greater market efficiency, as reflected in higher social welfare, and the increasingly prominent role of DERs particularly during periods of high renewable availability.



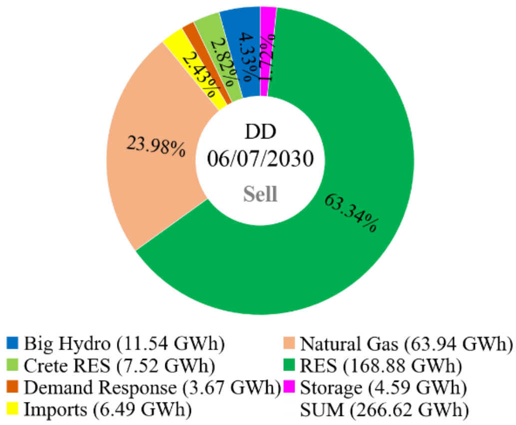
(a) *baseline scenario* - Buy



(b) *baseline scenario* - Sell



(c) 2030 scenario - Buy



(d) 2030 scenario - Sell

Figure 18. DD 06/07: Total daily cleared demand- and supply-side volumes by technology under the (a)–(b) baseline and (c)–(d) 2030 scenarios.

2.5.4.2 Results of reserve requirements and system imbalance calculation

For illustration, Figures 19–22 present the calculated upward and downward reserve requirements for the four representative days under the baseline and increased-flexibility cases, based on the methodology described in Section 2.2.4.1.

Across all evaluated seasonal days and simulation cases, both upward and downward FCR requirements exhibit a completely flat, static profile at 65 MW. This temporal and seasonal invariance stems directly from the ENTSO-E pro-rata allocation methodology for the Continental European Synchronous Zone (CESZ). Because the overall European FCR requirement is dimensioned to cover a fixed 3,000 MW reference contingency (the simultaneous loss of the two largest nuclear units or major demand blocks) and is distributed among TSOs based on annual net consumption and generation shares, the Greek control area's assigned share remains constant across all 15-minute dispatch intervals throughout the year. Consequently, FCR serves as a static primary frequency control baseline that does not vary with short-term load or solar fluctuations.

Figure 19. Upward reserve requirements under the baseline case.

Upward aFRR requirements demonstrate a strong diurnal pattern, affected by the schedule of natural gas units, that is actually driven by daily load dynamics and solar generation transitions. During off-peak overnight hours (00:00–05:00 EET), upward aFRR needs remain at their lowest level (approx. 200–280 MW) across all seasons. A steep step-up occurs during the morning ramp-up period (05:00–07:00 EET), rising to approximately 550–840 MW as morning demand increases and initial solar uncertainty rises. The requirement reaches its annual peak during the evening transition window (18:00–21:00 EET), fluctuating between 700 MW and 900 MW - most notably on high-demand summer days (06/07/2030) and winter days (21/01/2030). This evening peak reflects the confluence of high evening consumption and the rapid drop-off of photovoltaic generation, which demands maximum automatic secondary regulation capacity to maintain system balance.

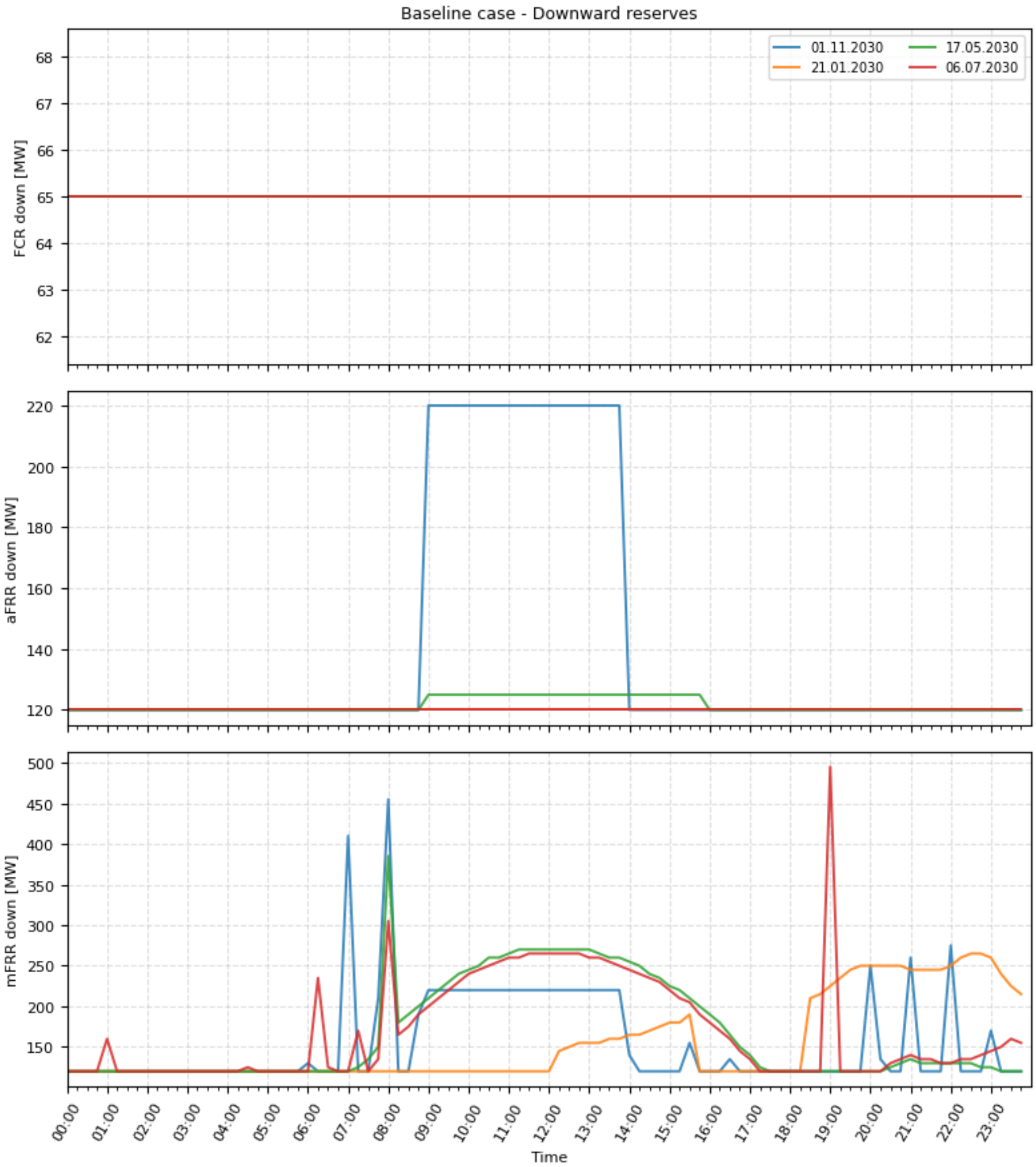


Figure 20. Downward reserve requirements under the baseline case.

Upward mFRR requirements represent the largest magnitude of reserve capacity dimensioned by the TSO, closely tracking intraday net load ramps and contingency requirements. Similar to aFRR up, mFRR up requirement profiles feature low nighttime values (200–350 MW) followed by an abrupt rise during the morning ramp. Throughout the afternoon and evening hours, requirements remain elevated at 700–900 MW. The highest stress point is recorded on the peak summer day (06/07/2030) around 18:00–19:00 EET, where upward mFRR spikes to nearly 1,200 MW in the baseline case and exceeds 1,300 MW in the increased flexibility case. These extreme requirement peaks highlight the heavy reliance on tertiary balancing capacity to cover steep evening load ramps when solar generation completely fades out.

Downward aFRR requirements remain tightly constrained at a baseline level of 120 MW for the vast majority of operational intervals. However, a distinct midday step-increase up to 220 MW is observed between 09:00 and 14:00 EET, particularly during autumn (01/11/2030) day. This temporary elevation during peak solar irradiance hours is explicitly dimensioned to cover potential over-generation risks and rapid solar supply surges when system demand is relatively mild. On winter and summer days, where baseline load is higher, downward aFRR requirements remain predominantly flat at 120 MW, as high underlying consumption naturally absorbs solar feed-in without requiring elevated automatic downward regulation margins.

Figure 21. Upward reserve requirements under the increased-flexibility case.

Downward mFRR requirements exhibit the most volatile and seasonally sensitive behavior among all reserve products. Outside of daylight hours, requirements rest at a minimum baseline of approximately 120 MW. On high-RES spring (17/05/2030) and summer (06/07/2030) days, downward mFRR forms a broad midday plateau reaching 250–280 MW between 10:00 and 16:00 EET to provide necessary downward regulation against renewable forecast errors. Crucially, the downward mFRR profile is punctuated by sharp, high-magnitude transient spikes—reaching 400–500 MW in the baseline scenario and up to 900 MW in the increased flexibility scenario during rapid transition windows (e.g., 08:00 EET and 19:00 EET). These steep spikes reflect brief operational intervals where sudden shifts in interconnector schedules, rapid thermal unit ramping, or steep solar transitions necessitate massive downward regulation margins to prevent over-frequency events.

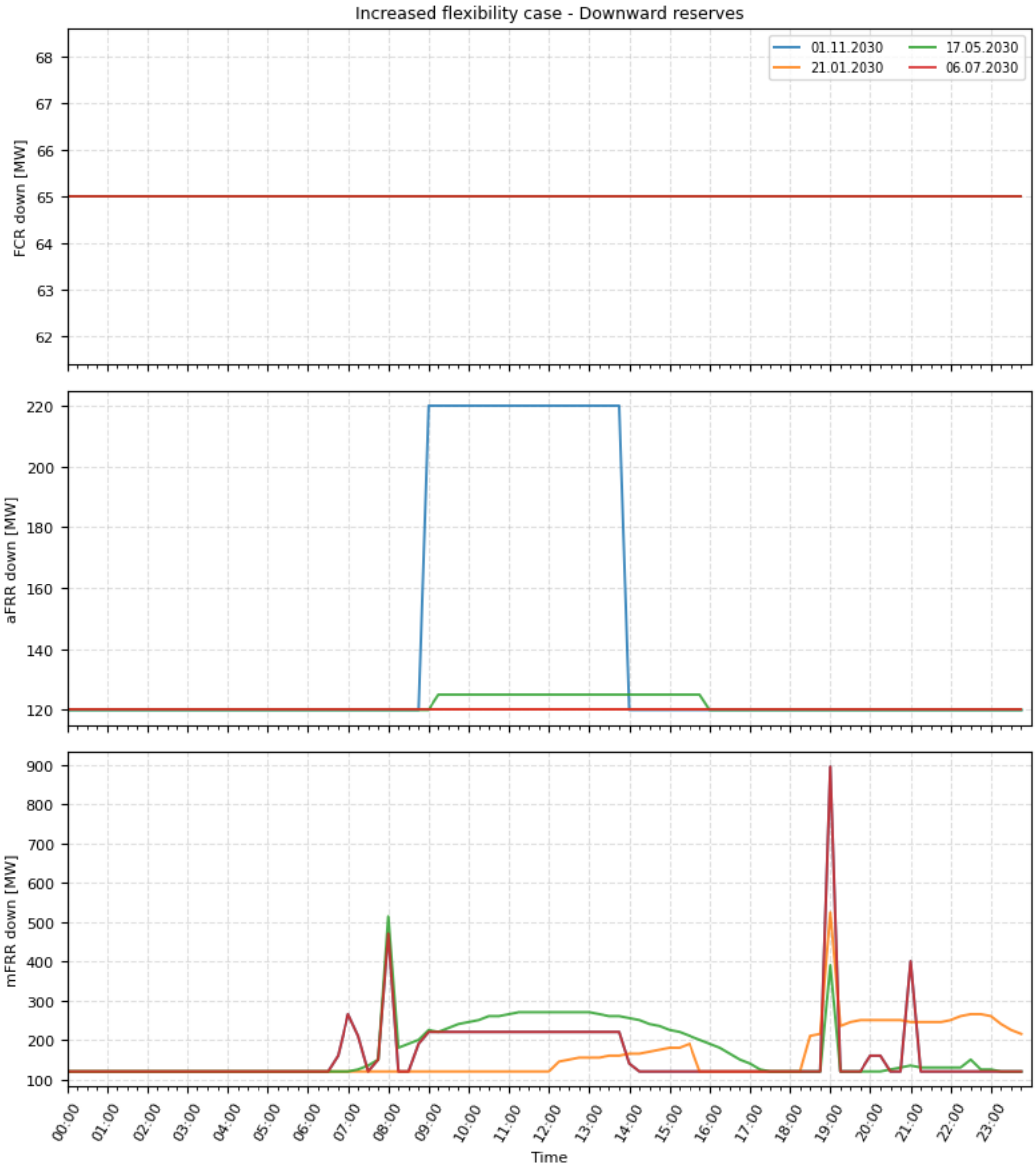


Figure 22. Downward reserve requirements under the increased-flexibility case.

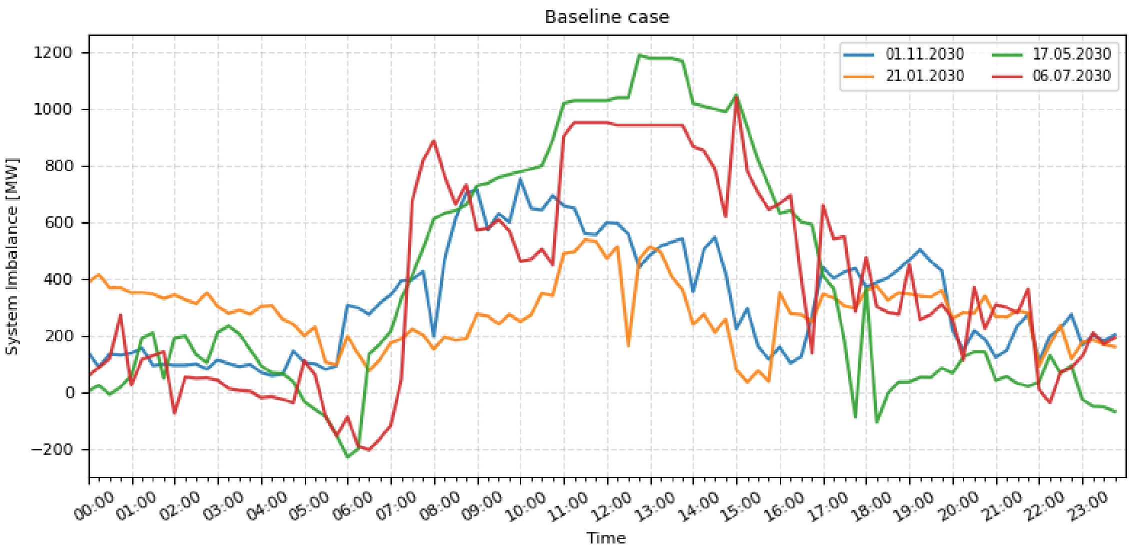


Figure 23. Projected imbalances under the baseline case.

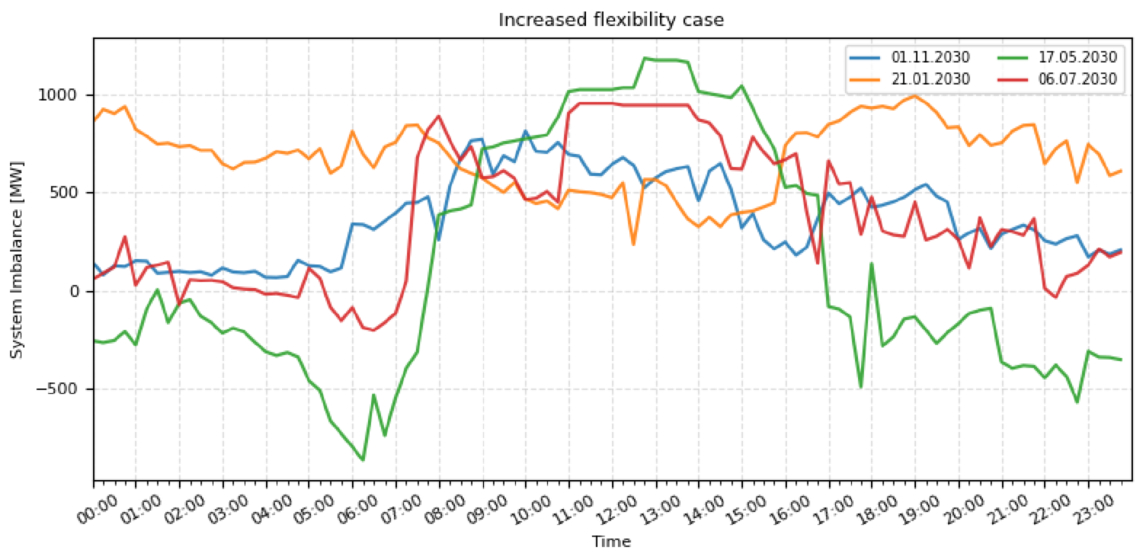


Figure 24. Projected imbalances under the increased-flexibility case.

Figures 23 and 24 depict the projected 15-minute system imbalances for the baseline and increased-flexibility cases. The imbalance profiles are derived from the projected differences between DAM schedules and updated load and RES conditions, using the assumptions described in Sections 2.2.4.1 and 2.5.1.2.

Figures 23 and 24 show that the projected imbalance profiles vary materially by operating day and scenario input set, including both positive intervals requiring upward balancing energy and negative intervals requiring downward balancing energy. The differences between the baseline and increased-flexibility profiles reflect the scenario-specific imbalance inputs used in each run and should not be interpreted as an endogenous effect of BESS or demand-response activation alone.

2.5.4.3 Results of balancing market DT

Purpose, scope and interpretation

Eight balancing-market result workbooks were assessed for four representative operating days: 1 November 2025, 21 January 2026, 17 May 2026 and 6 July 2026. Each day is represented by two model configurations. The reduced-service configuration excludes TSO and DSO congestion-management requirements and FFR, while the full-flexibility configuration activates these products and allows BESS and demand response to contribute according to their eligibility and technical constraints.

The comparison covers final dispatch, balancing energy, FCR, aFRR, mFRR, TSO-CM, DSO-CM, FFR, BESS charging and discharging, DR activation, natural-gas commitment and unit-level operational movements. Final schedules are converted to energy through the 15-minute model resolution,

$$E = \sum_{t=1}^{96} P_t \cdot 0.25,$$

while ancillary-service results are aggregated as daily capacity volumes,

$$V_s = \sum_{t=1}^{96} R_{s,t} \cdot 0.25.$$

The latter indicate reserved capacity over time, not necessarily activated energy.

A methodological distinction is essential. The two workbooks of a given day do not always differ only in the activation of BESS, DR, congestion management and FFR. For 1 November, 21 January and 6 July, the common-product requirements or the participation of BESS/DR in the reduced configuration also differ. 17 May is the only fully controlled scenario pair, because the common BE, FCR, aFRR and mFRR requirements are identical and BESS/DR provide none of these products in the reduced case. The resulting comparability assessment is summarised in Table 8.

Table 8. Comparability of the four scenario pairs.

Day	Difference in common requirements	BESS/DR already present in reduced case	Interpretation strength
17/05	0.00%	No	Controlled counterfactual
01/11	5.57%	Yes	Comparison of configurations
06/07	8.14%	Yes	Comparison with attribution limits
21/01	20.71%	Yes	Input differences dominate

The distinction does not invalidate the remaining comparisons. It changes the analytical question that each pair can answer. The 17 May pair isolates the operational effect of introducing the full flexibility portfolio. The other three pairs show how two complete balancing configurations operate under somewhat different input conditions, but their dispatch differences should not be attributed exclusively to BESS, DR or the additional congestion-management and FFR products.

This methodological issue is visualised in Figure 25. The figure combines system scale, upward-service intensity, peak reserve stack, hydro flexibility leverage, BESS throughput, average online natural-gas units and reduced/full input mismatch on a single canvas. The particularly large mismatch shown for 21 January confirms that this pair is best interpreted as a comparison of operating configurations rather than a controlled estimate of the flexibility effect. Conversely, the zero mismatch shown for 17 May supports its use as the principal controlled counterfactual.

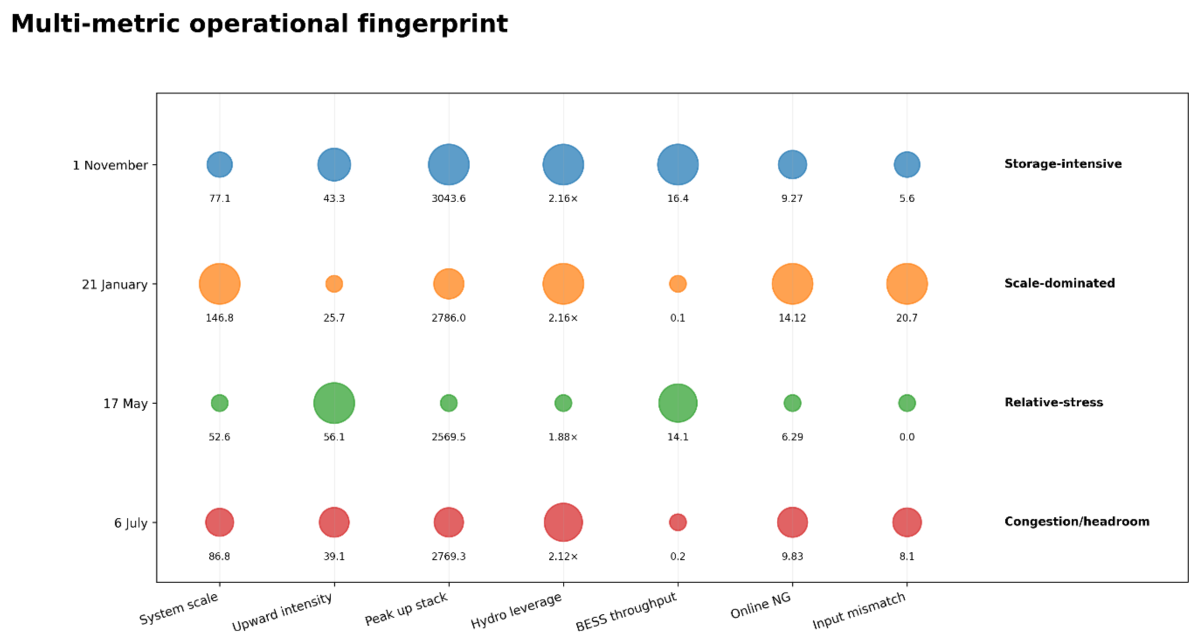


Figure 25. Compact comparison of system scale, reserve stress, hydro leverage, BESS use, thermal commitment and scenario-input comparability.

Four distinct operating regimes

The four days represent structurally different balancing challenges rather than variations of a single operating condition. Table 9 summarises the operational fingerprint of each full-flexibility case.

Table 9. Compact operational fingerprint of the full-flexibility cases.

Day	NG / Hydro energy	BE Up / Down	CM+FFR	BESS throughput	Online NG	Dominant challenge
01/11	57.70 / 19.44 GWh	8.83 / 0.00 GWh	8.41 GWh	16.44 GWh	9.27	Storage-intensive multi-service operation
21/01	114.57 / 32.18 GWh	16.24 / 0.00 GWh	5.25 GWh	0.14 GWh	14.12	Maximum absolute system scale
17/05	38.65 / 13.97 GWh	10.75 / 0.01 GWh	10.26 GWh	14.12 GWh	6.29	Relative flexibility scarcity
06/07	72.73 / 14.05 GWh	9.27 / 0.30 GWh	9.47 GWh	0.17 GWh	9.83	Congestion and fast headroom

The contrast between absolute system scale and relative operational stress is shown directly in Figure 26. The horizontal axis represents daily natural-gas and hydropower production, while the vertical axis represents upward-service volume relative to conventional generation. Bubble size represents BESS throughput. The figure distinguishes four operating regimes:

- 21 January occupies the high-scale operating space;
- 17 May occupies the high-relative-stress space;
- 1 November is the most energy-cycling-intensive BESS case;
- 6 July combines low BESS throughput with high service intensity, indicating a headroom-dominated storage role.

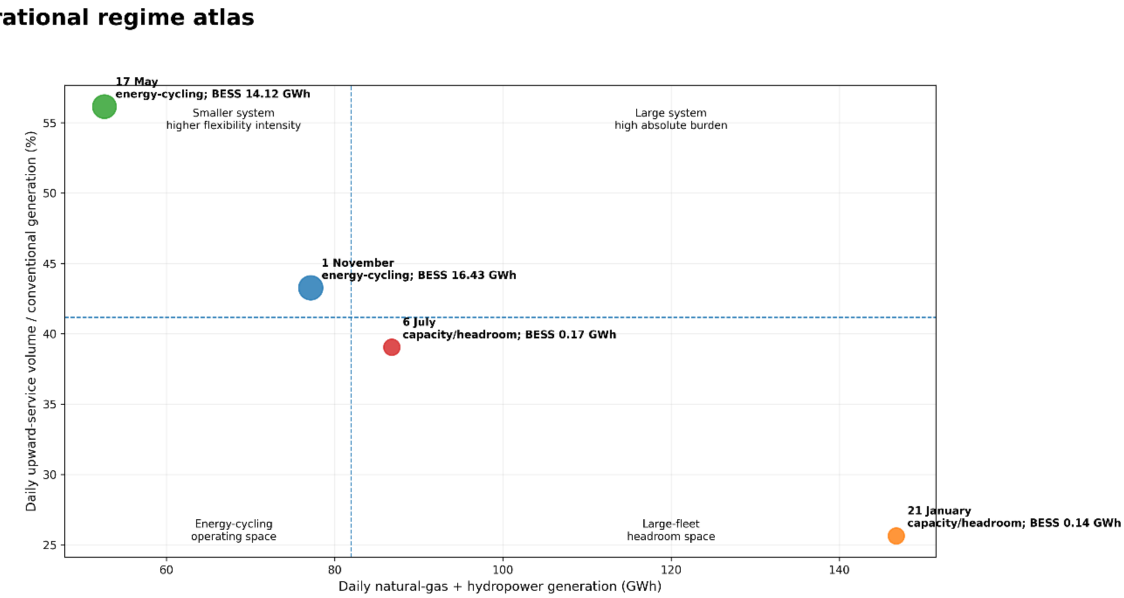


Figure 26. Operating-regime map of conventional system scale, upward-service intensity and BESS throughput.

The temporal structure behind these daily indicators is provided by Figure 27. Rather than presenting four repetitive charts, the figure displays the 96-period FCR, aFRR, mFRR, TSO-CM, DSO-

CM and FFR requirements as four vertically offset ribbons. It therefore shows not only the magnitude of the daily requirement but also whether the operational challenge is concentrated in a short critical window or sustained over several hours.

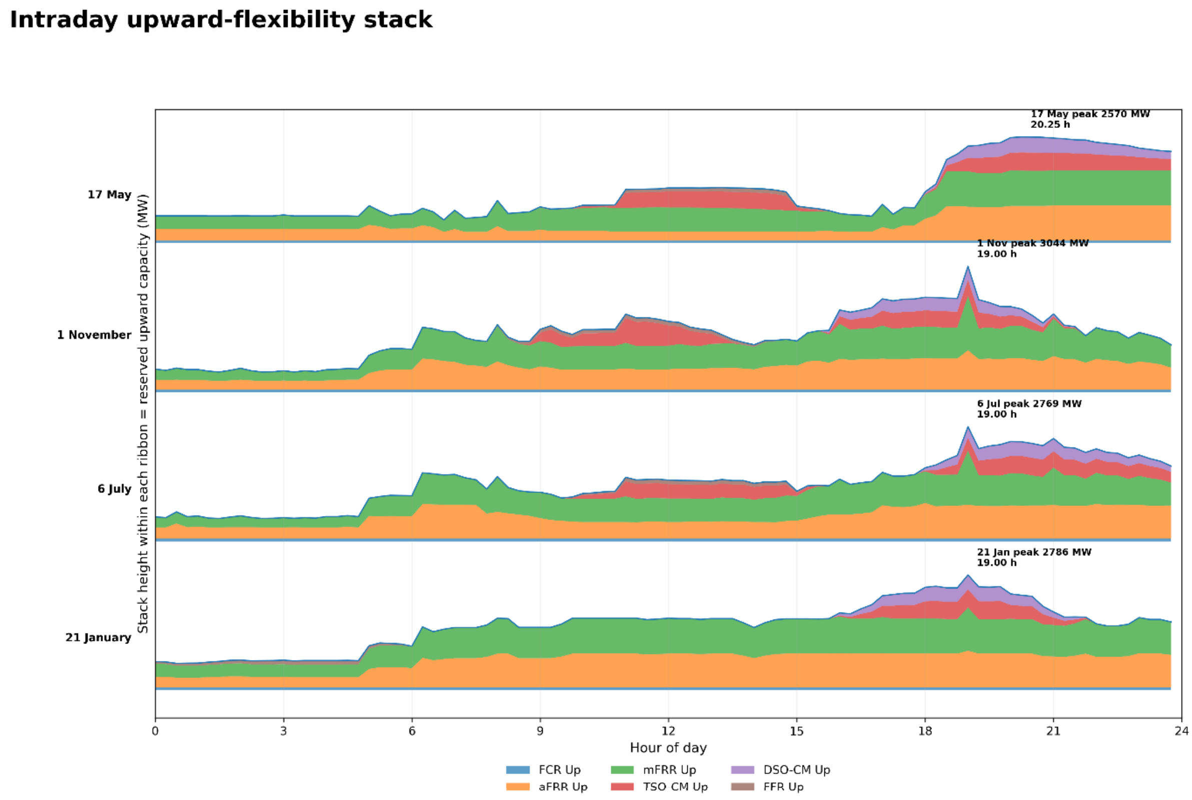


Figure 27. Temporal composition of upward FCR, aFRR, mFRR, congestion-management and FFR requirements over the 96 periods.

21 January: the largest system, but not the tightest one

The 21 January case has the highest absolute production and balancing requirement. Natural-gas and hydro output together reach approximately 146.76 GWh, with natural gas alone supplying 114.57 GWh. More than 14 gas-fired units are online on average, providing a broad commitment base and substantial aggregate reserve headroom.

The day is almost entirely upward-driven. BE Up reaches 16.24 GWh, no material BE Down is required, and the upward ancillary-service volume is approximately 3.8 times the downward volume. It also contains the highest aFRR Up and mFRR Up volumes among the four days.

Nevertheless, the day is not the most stressed relative to available conventional output. The largest simultaneous upward ancillary stack corresponds to approximately 35% of natural-gas and hydro production in the same period. The large committed fleet absorbs the absolute requirement without the extreme relative scarcity observed on 17 May.

BESS throughput is only 0.14 GWh, yet the batteries provide several GWh-equivalent of reserve and flexibility capacity. Their role is not primarily energy shifting. It is the provision of fast, bidirectional headroom around a nearly static energy position. This operating mode is examined in greater depth in Figure 28.

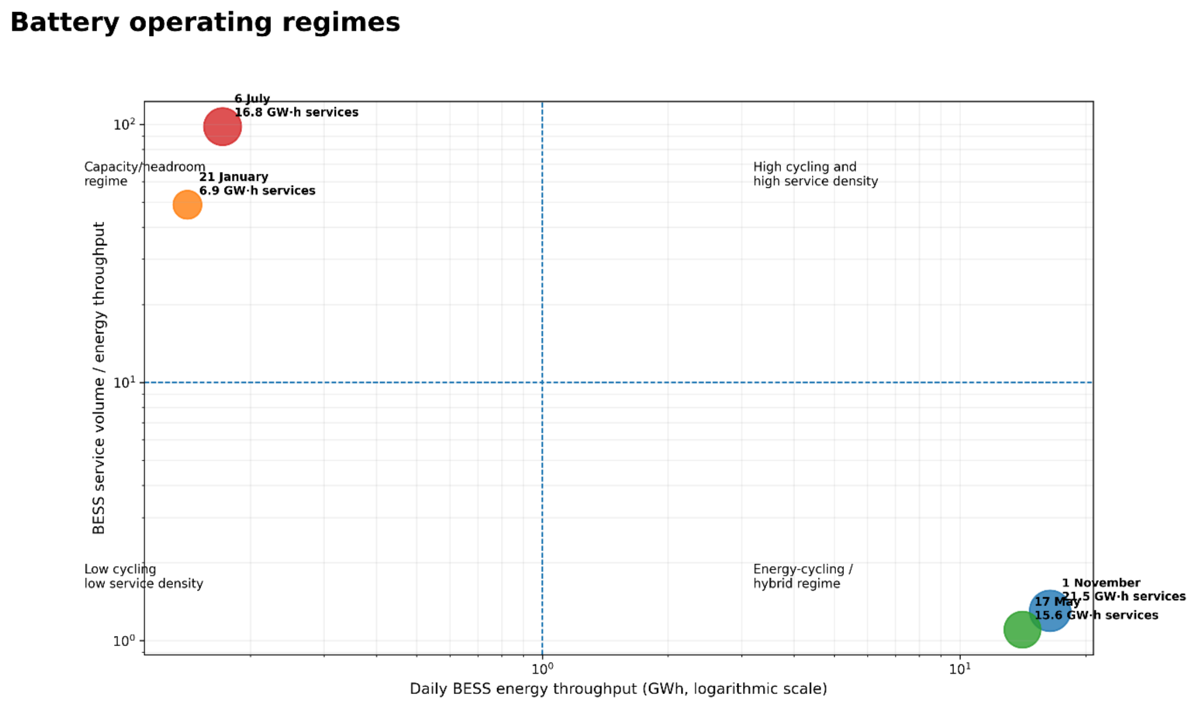


Figure 28. Distinction between energy-cycling and capacity/headroom-based battery operation.

17 May: the highest relative flexibility stress

The 17 May case is smaller in energy terms but considerably tighter operationally. Natural-gas output is only 38.65 GWh, hydro supplies 13.97 GWh, and the average number of online gas units falls to 6.29.

At the same time, the system must accommodate:

- 10.75 GWh of BE Up;
- substantial aFRR and mFRR requirements;
- the largest combined CM and FFR volume, at 10.26 GWh;
- a peak upward service stack equal to 104.4% of simultaneous natural-gas and hydro output.

This ratio does not imply that reserved capacity is being converted directly into the same amount of energy. It shows that the volume of upward headroom simultaneously required is exceptionally large relative to the scheduled operating point. The day therefore places the strongest pressure on available flexibility margins.

Figure 26 identifies this case as the high-relative-stress operating regime. Figure 27 further shows the intraday composition of this stress: balancing and reserve products are layered on top of a comparatively modest committed conventional fleet.

BESS throughput reaches 14.12 GWh, and DR is also materially activated. Storage operates simultaneously as an energy-shifting resource and a reserve provider. Among the four days, 17 May offers the clearest case in which distributed flexibility reduces dependence on the conventional fleet.

1 November: integrated battery energy shifting and service stacking

The 1 November case has the highest BESS throughput, approximately 16.44 GWh. Batteries are not merely held in reserve; they charge and discharge extensively over the day while also providing mFRR, congestion management and FFR.

This produces a genuinely integrated operating regime. The batteries:

- shift energy between periods;
- maintain upward and downward headroom;
- contribute to balancing;
- provide fast frequency response;
- relieve both system-level and local congestion.

Hydro is particularly important for TSO-CM Up, supplying approximately 81.4% of the daily volume. TSO-CM Down is more diversified, with natural gas, hydro and the TSO battery all contributing materially. The day therefore provides the most complete example of multi-service coordination between energy and flexibility markets.

Figure 27 shows that the 1 November flexibility requirement is distributed across several products over the day rather than being represented by one isolated reserve peak. Figure 26 places the case in the high-throughput region, confirming that its distinctive feature is not only service provision but also substantial intertemporal energy movement.

6 July: high service value with very limited battery cycling

The 6 July case is characterised by significant congestion-management and FFR needs, but only 0.17 GWh of BESS throughput. The batteries nevertheless provide considerable reserve and congestion-management capacity.

This is a headroom-dominated storage regime. BESS value is created through power availability, fast response and the ability to move in either direction, rather than through substantial daily energy transfer.

Hydro contributes strongly to TSO-CM Up, while TSO-CM Down remains predominantly natural-gas-based. The day also includes meaningful BE Down, unlike 1 November and 21 January, making bidirectional balancing capability more relevant.

The temporal service composition in Figure 27 identifies the Market Time Units in which upward FCR, aFRR, mFRR, congestion management and FFR requirements are most intensive.

The quantitative differences between the full- and reduced-service configurations are reported in Table 10.

Table 10. Full-flexibility minus reduced-service results.

Day	Δ NG	Δ Hydro	Δ BESS throughput	Δ online NG	Δ NG ramping	Principal observation
17/05	−2.95 GWh	−0.56 GWh	+13.57 GWh	−0.36	−5.4%	Clean conventional-flexibility substitution
06/07	−5.36 GWh	≈0	+0.13 GWh	−0.35	+23.3%	Less NG energy, more NG movement
01/11	≈0	+0.04 GWh	−1.73 GWh	+0.02	+12.6%	More services without more cycling
21/01	+7.63 GWh	≈0	+0.09 GWh	+1.05	+8.8%	Different BE profile dominates

The relationship between natural-gas energy and unit-level operational movement is visualised in Figure 29. The horizontal axis shows the full-minus-reduced change in natural-gas generation, while the vertical axis shows the corresponding change in gas-unit movement. Bubble size represents the change in BESS throughput, and the controlled 17 May comparison is marked separately.

The figure demonstrates that energy displacement and operational smoothing are different outcomes. The 6 July case moves into the “lower NG energy but more movement” quadrant, whereas 17 May is the only case combining lower natural-gas generation with lower thermal movement under fully comparable requirements.

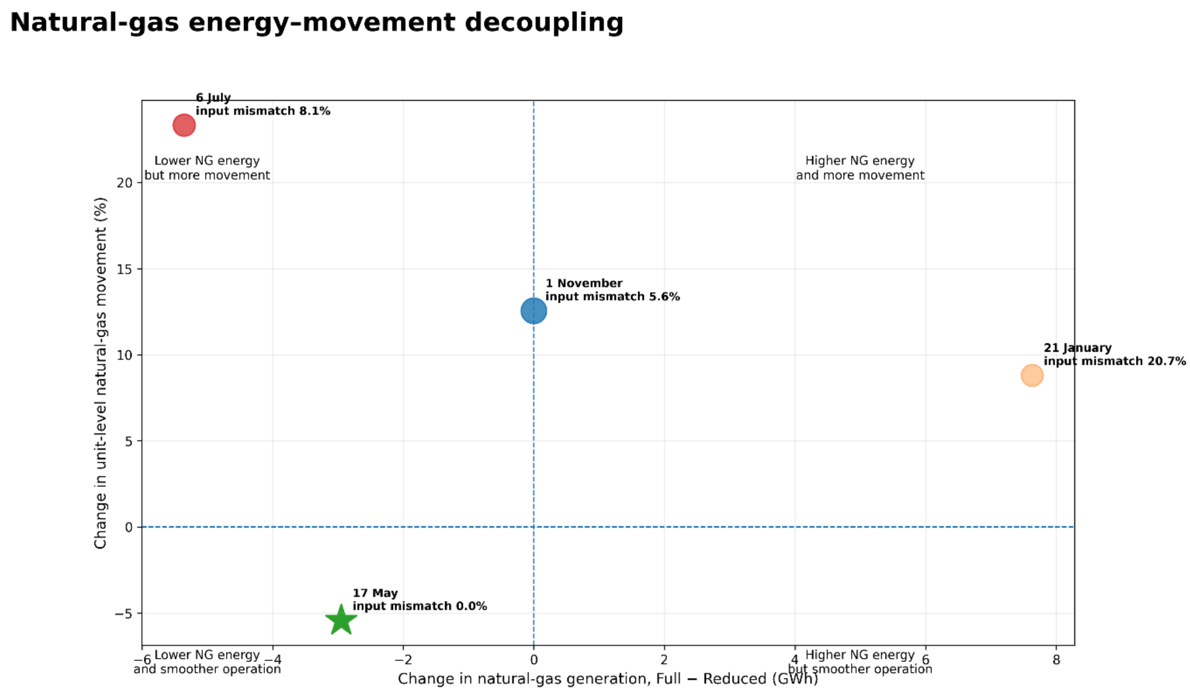


Figure 29. Full-versus-reduced changes in natural-gas generation and unit-level movement, highlighting that lower gas output does not always imply smoother operation.

17 May: direct substitution of conventional reserves

The 17 May results provide the strongest evidence of the effect of BESS and DR because the common service requirements are identical in the two scenarios.

In the reduced case, natural-gas and hydro units supply approximately 32.36 GWh of FCR, aFRR and mFRR. BESS and DR provide none. In the full case, conventional provision falls to 27.01 GWh, while BESS and DR supply 5.354 GWh.

The transfer is effectively one-for-one:

$$-5.354 \text{ GWh conventional provision} = +5.354 \text{ GWh BESS/DR provision.}$$

The result is illustrated in Figure 30. The figure preserves the same total FCR, aFRR and mFRR volume in both configurations and shows how 5.354 GWh moves directly from natural gas and hydropower to BESS and DR. It also reports the associated reductions in natural-gas energy, online units and thermal movement.

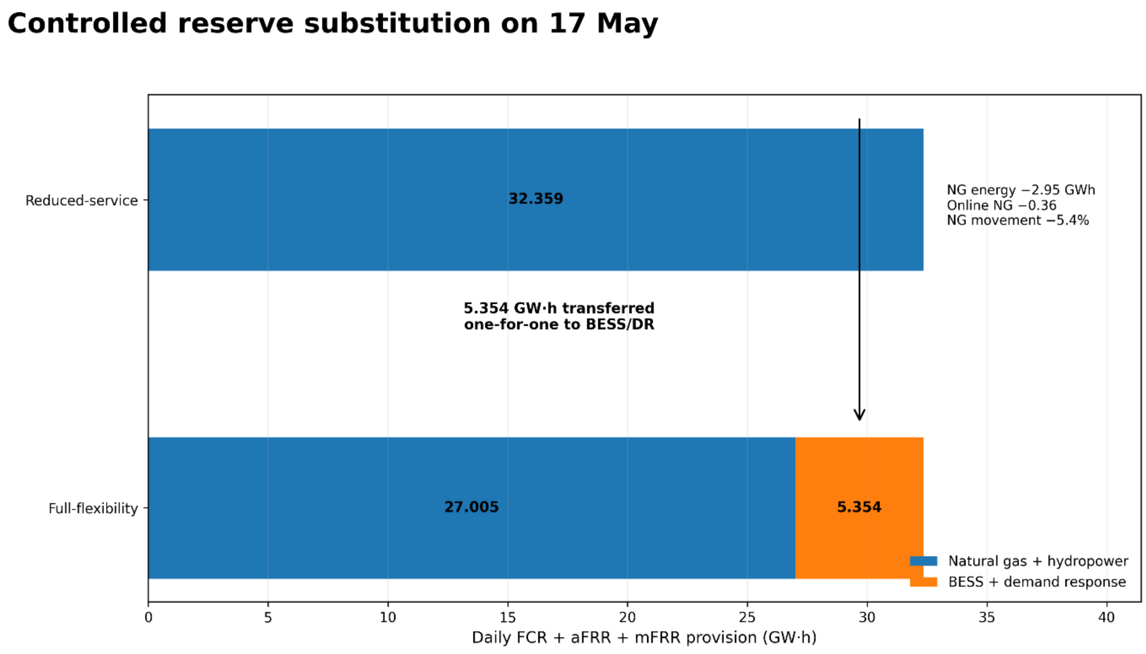


Figure 30. One-for-one transfer of 5.354 GWh from conventional reserve provision to BESS and demand response under identical common requirements.

The operational effect extends beyond reserve allocation. Natural-gas generation declines by 2.95 GWh, hydro output declines by 0.56 GWh, the average number of online gas units falls by 0.36 and gas-unit ramping decreases by 5.4%.

The full portfolio therefore reduces both conventional energy production and operational reserve burden. This is the most robust scenario result and should be treated as the central evidence of flexibility substitution in the deliverable.

The mFRR reallocation is particularly clear. In mFRR Up, the reduced case is supplied only by natural gas and hydro. In the full case, the TSO battery assumes approximately 28.5% and DR approximately 3.7%, reducing both gas and hydro shares. In mFRR Down, the natural-gas share falls from more than 82% to approximately 47%, with BESS covering close to 30%.

The 17 May case is therefore the central evidence that a coordinated flexibility portfolio can reduce both conventional energy production and conventional reserve burden.

1 November: reserve value without additional energy movement

On 1 November, natural-gas generation remains essentially unchanged between the two configurations and hydro output changes by only 0.04 GWh. The average number of committed gas units is also stable.

Despite the activation of approximately 8.41 GWh of CM and FFR, BESS throughput is 1.73 GWh lower in the full configuration. This is not contradictory. Reserve and congestion services can be supplied through available headroom without requiring an equivalent quantity of charging or discharging.

The result shows that:

$$\text{additional BESS services} \not\Rightarrow \text{additional BESS cycling}.$$

The batteries are repositioned differently and use their available power capacity more efficiently across products. The full case therefore extracts more flexibility value per unit of energy throughput.

Natural-gas ramping nevertheless increases by 12.6%. Additional BESS flexibility does not guarantee smoother operation of every gas unit. The remaining online generators may still be required to redistribute production more frequently as the model co-optimises energy, reserves and congestion services.

Figure 29 places 1 November close to zero change in gas energy but above zero change in gas-unit movement. This confirms that the full-flexibility architecture changes the internal use of the thermal fleet even where total natural-gas production remains almost unchanged.

6 July: lower natural-gas production but more intensive thermal movement

The full 6 July configuration reduces natural-gas generation by 5.36 GWh and the average number of online gas units by 0.35. However, unit-level gas ramping increases by 23.3%.

This is a critical distinction for operational assessment. Lower daily natural-gas output does not necessarily imply less demanding thermal operation. With fewer units online and more service interactions, the remaining units can be required to move more aggressively within the day.

Figure 29 highlights that changes in natural-gas generation and unit-level movement need not have the same sign: lower gas energy can coincide with more intensive movement of the remaining online fleet.

Part of the observed change is also linked to non-identical mFRR requirements between the two workbooks. Consequently, the result supports a configuration-level interpretation—lower gas energy but greater dispatch movement—rather than a strict causal attribution to CM and FFR.

21 January: balancing-energy inputs dominate the scenario difference

Natural-gas production increases by 7.63 GWh in the full 21 January case. This increase should not be interpreted as evidence that BESS, DR or CM increase gas dependence. The BE Up requirement rises from approximately 6.76 GWh in the reduced configuration to 16.24 GWh in the full configuration.

The different imbalance profile is therefore the dominant driver. For the more comparable reserve products, the full case still transfers a modest quantity of provision from conventional resources to BESS/DR. However, this effect is small relative to the BE input difference.

Figure 29 places the 21 January case in the high-energy/high-commitment region and the 17 May case in the lower-energy but higher-relative-reserve-stress region.

The 21 January case demonstrates why scenario harmonisation is indispensable. A fully controlled counterfactual should preserve the same BE, FCR, aFRR and mFRR requirements and modify only resource eligibility and the presence of the additional CM and FFR products.

Technology roles and system architecture

Natural gas: lower energy does not mean a lower security role

Natural gas remains the backbone of security-oriented reserve provision. Across the full scenarios:

- FCR Up is supplied entirely by natural gas;
- FCR Down is almost entirely natural-gas-based;

- aFRR Down is predominantly or exclusively supplied by gas units;
- TSO-CM Down remains largely dependent on gas-fired flexibility.

This reflects more than installed capacity. Gas units provide downward regulation, synchronised reserve and stable operating margins that are not fully replaced by the modelled BESS and DR portfolios.

The technology allocation is summarised in Figure 31. For each service and day, the figure identifies the dominant technology and its daily share, together with the main supporting technology where its contribution exceeds 5%. The persistent natural-gas dominance of FCR and downward regulation is immediately visible.

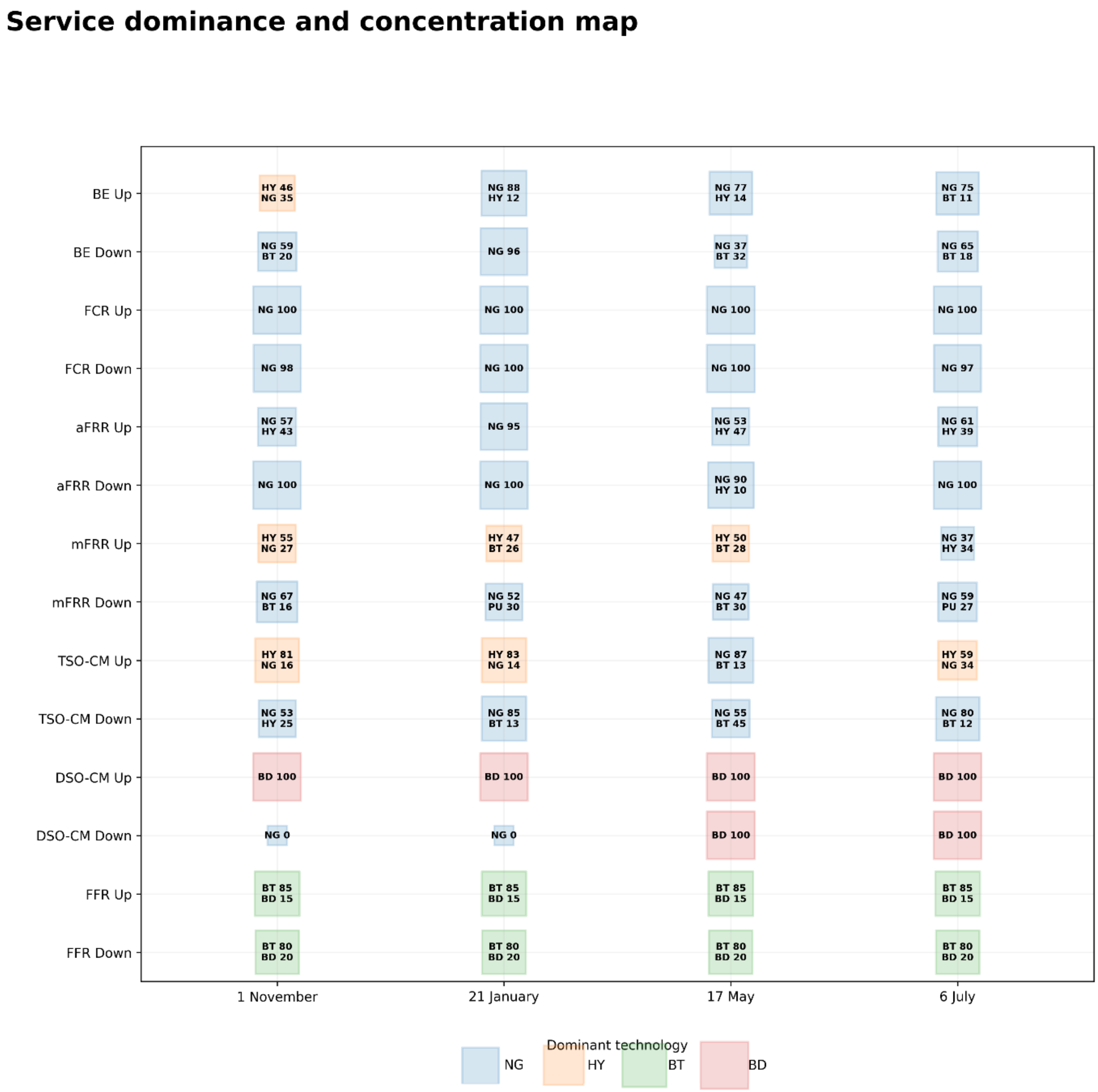


Figure 31. Dominant and supporting technologies across balancing energy, reserves, congestion management and FFR for all four days.

The full flexibility architecture therefore does not remove thermal generation. It changes how intensively thermal resources are used and which flexibility products they must cover.

Hydropower: flexibility value far above its energy share

Hydro contributes a much larger share of mFRR Up than of daily conventional energy. Table 11 compares hydropower's reserve leverage with the corresponding BESS utilisation indicators.

Table 11. Hydropower and BESS leverage indicators.

Day	Hydro energy share	Hydro mFRR Up share	Hydro leverage	BESS throughput	BESS service/throughput	BESS regime
01/11	25.2%	54.5%	2.16×	16.44 GWh	1.31	Energy-cycling
21/01	21.9%	47.5%	2.17×	0.14 GWh	48.8	Headroom
17/05	26.5%	50.0%	1.89×	14.12 GWh	1.10	Hybrid
06/07	16.2%	34.4%	2.12×	0.17 GWh	98.1	Headroom

Hydro's mFRR Up share is approximately twice its energy share on every day. Its principal system contribution is therefore not limited to energy production. It is a high-value provider of upward reserve, fast ramping and congestion relief.

This relationship is shown in Figure 32. For each day, the figure follows hydropower from its share of conventional energy to its share of mFRR Up and TSO-CM Up. The leverage ratios reported over the mFRR points quantify the extent to which hydropower's flexibility contribution exceeds its energy contribution.

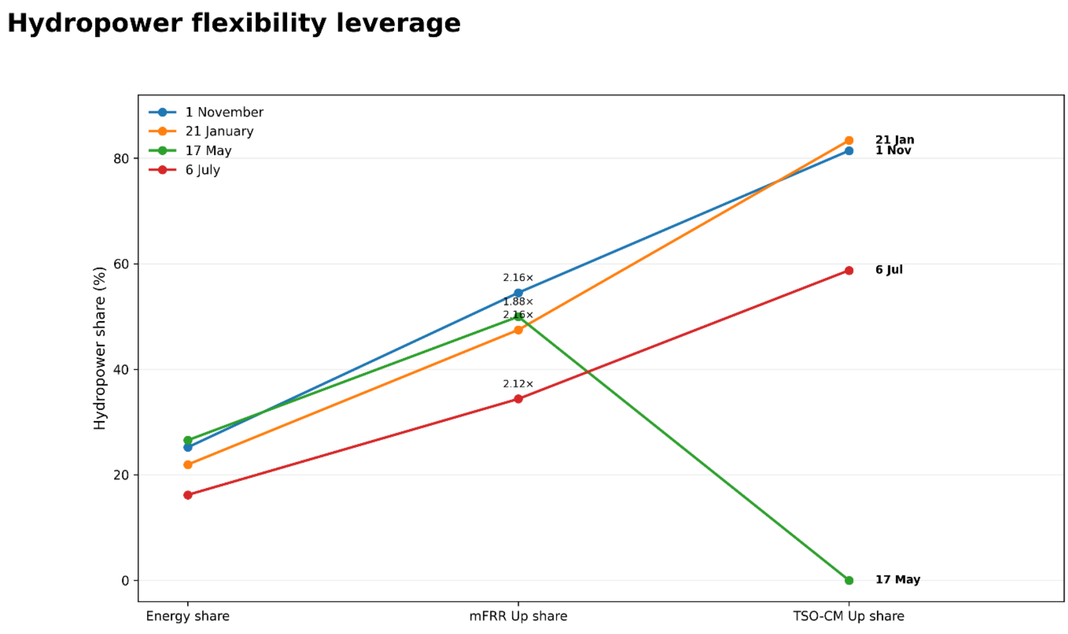


Figure 32. Comparison of hydropower's energy share with its contribution to mFRR Up and TSO-CM Up.

The result is particularly strong for TSO-CM Up. Hydropower supplies approximately 59% on 6 July, 81% on 1 November and 83% on 21 January. On 17 May, natural gas and BESS assume a greater congestion-management role, reflecting the different hydropower schedule and relative scarcity conditions.

Figure 31 complements this interpretation by showing that hydropower is the dominant or principal supporting technology in many upward services, despite not being the dominant daily energy source.

BESS: two distinct economic and physical functions

The results reveal two different BESS operating regimes.

On 1 November and 17 May, batteries cycle substantial energy. They shift energy between periods while also providing reserves and congestion services. Their value is a combination of energy arbitrage, balancing and capacity provision.

On 6 July and 21 January, batteries provide large service volumes with negligible energy throughput. Their value is almost entirely associated with power availability, fast response and bidirectional headroom.

The distinction is shown in Figure 28. The horizontal axis represents daily BESS throughput, while the vertical axis represents BESS service volume divided by energy throughput. Bubble size represents total BESS service provision.

The figure separates:

- 1 November and 17 May, which occupy the energy-cycling or hybrid region;
- 6 July and 21 January, which occupy the capacity/headroom region.

The service-volume-to-throughput ratio is not an efficiency indicator. It is a diagnostic measure of whether storage is being used primarily as an energy asset or as a capacity asset. A battery that cycles only 0.14 GWh but provides several GWh-equivalent of reserve capacity is not underutilised; it is performing a different system function.

TSO and DSO batteries perform different roles

The TSO battery provides the majority of total BESS service volume. It participates in balancing energy, mFRR, TSO-CM and most FFR.

The DSO battery has a narrower but strategically distinct function:

- balancing energy;
- local DSO congestion management;
- 15% of daily FFR Up;
- 20% of daily FFR Down.

The full-flexibility cases therefore do not represent a homogeneous storage fleet. They represent a coordinated two-level architecture in which the TSO battery supports system balancing and the DSO battery provides local and fast-response services.

Figure 31 shows this separation clearly. TSO BESS appears as a supporting technology in mFRR and TSO-CM, whereas DSO BESS dominates DSO-CM and provides the predefined minority share of FFR.

The result that DSO-CM is supplied entirely by the DSO battery follows from the model's eligibility structure. It should not be interpreted as evidence that batteries would necessarily dominate a broader, technology-neutral local flexibility market.

Demand response: low energy volume, high marginal value

DR energy movement is modest relative to conventional production and battery throughput. Nevertheless, DR contributes to mFRR and TSO-CM and reduces the need to preserve equivalent reserve headroom on generation units.

Its value is marginal and strategic rather than volumetrically dominant. DR becomes especially valuable when BESS headroom is simultaneously allocated to other services or when a small quantity of rapid flexibility avoids the commitment or repositioning of an additional thermal unit.

The cross-service role of DR is visible in Figure 31 and in the final system architecture shown in Figure 33. DR rarely dominates a service, but it repeatedly appears as a supporting technology in mFRR and TSO-CM. This is precisely the expected role of a resource whose value lies in high responsiveness rather than large daily energy volume.

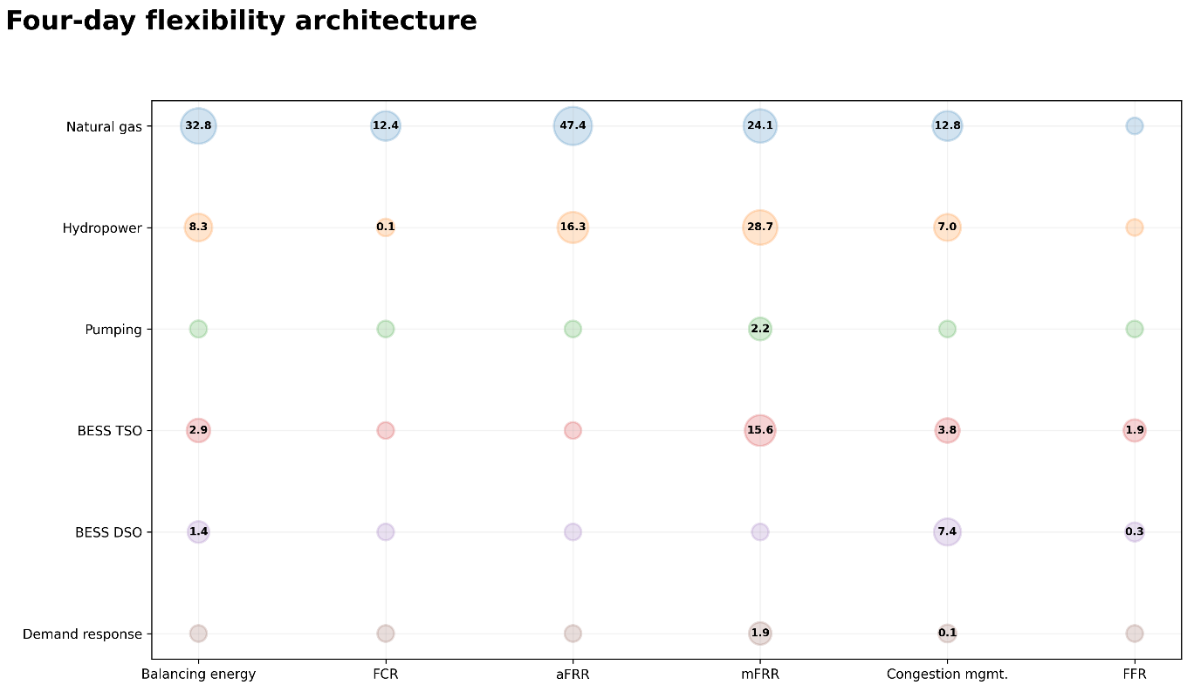


Figure 33. Aggregated technology contributions across balancing energy, reserve, congestion-management and fast-response service layers.

Fixed pumping and residual mFRR Down

Pumped-storage mFRR Down is treated as an exogenous schedule rather than an optimisation decision. The fixed quantity is subtracted from the total requirement:

$$RR3MN_t^{residual} = max\left(0, RR3MN_t - \sum_p Pump_{p,t}\right).$$

The model then allocates only the residual quantity among natural gas, hydro, BESS and DR.

Fixed pumping is material on 6 July and 21 January and zero in the analysed 1 November and 17 May results. In some intervals the fixed pumping schedule exceeds the original requirement. The max(0,·) formulation prevents a negative residual, but fixed overcoverage can remain.

This is not a solver imbalance. It is a direct consequence of treating the pumping schedule as fixed. For transparent reporting, the deliverable should distinguish five quantities:

1. original mFRR Down requirement;
2. fixed pumping provision;
3. non-negative residual requirement;
4. optimised contribution from the remaining resources;
5. fixed overcoverage.

The full accounting is shown in Figure 34. The bar segments separate fixed pumping from the optimised residual requirement, while the horizontal marker represents the original requirement. The overcoverage labels identify both the daily overcoverage volume and the number of affected intervals.

Figure 34 is particularly important for 21 January, where fixed pumping is substantial and overcoverage occurs in a relatively large number of periods. Presenting the fixed and optimised quantities separately prevents the exogenous schedule from being misinterpreted as a model-selected flexibility contribution.

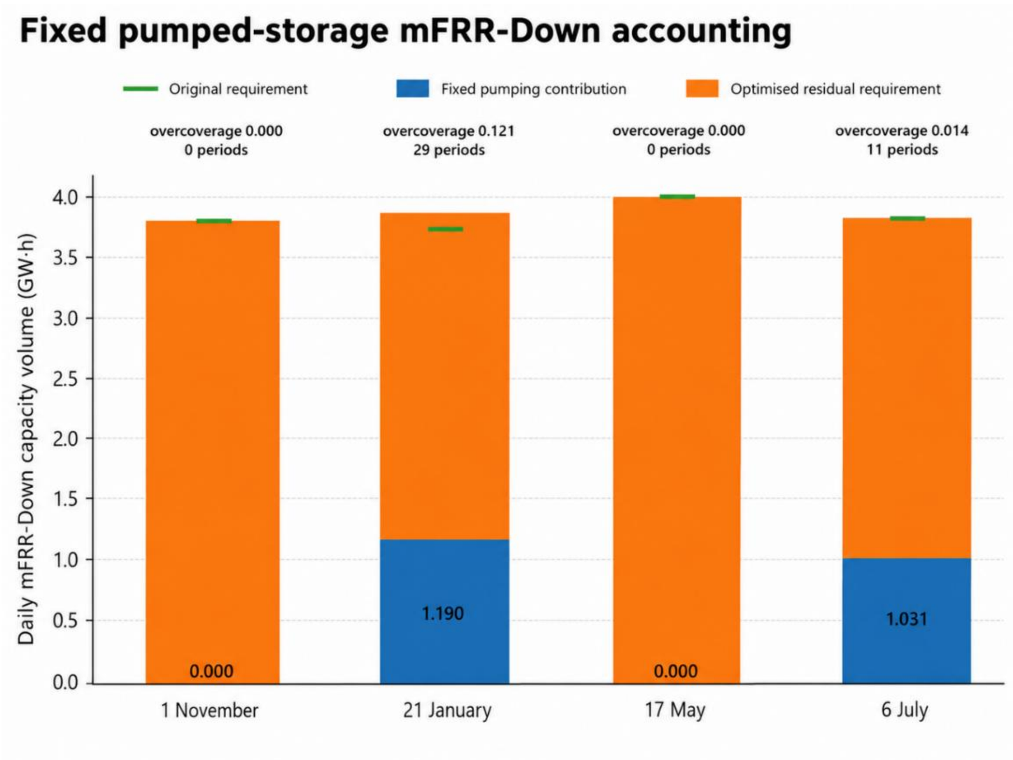


Figure 34. Decomposition of the original requirement into fixed pumping, residual optimised provision and overcoverage.

Daily technology targets and interval-level concentration

Exact daily technology shares do not guarantee diversified provision in every 15-minute period.

The model can satisfy:

- an exact daily FFR Up split of 85% TSO BESS and 15% DSO BESS;
- an exact daily FFR Down split of 80% and 20%;
- exact daily FCR and aFRR technology shares;

while still assigning the complete service to one provider in individual intervals.

The same issue appears in mFRR. The maximum contribution of a single provider reaches approximately:

- 88.8% on 6 July;
- 81.3% on 1 November;
- 68.4% on 17 May;
- 42.9% on 21 January;

for mFRR Up. For mFRR Down, one resource supplies the complete optimised service in some intervals on 6 July, 1 November and 21 January.

Three concepts must therefore remain separate:

- daily technology diversification, describing the aggregate daily mix;
- interval-level aggregator diversification, describing how many providers are active at each moment;
- unit-level concentration, describing the maximum dependence on one resource.

Figure 31 reports the dominant technology and the principal supporting technology for every service and day. It therefore provides a compact picture of daily technology-level concentration. It should not, however, be interpreted as a complete measure of interval-level provider concentration. A daily technology allocation can appear diversified even where one unit or one aggregator dominates individual critical periods.

Figure 27 provides the necessary temporal complement. It shows when each service layer becomes active, but not which individual unit supplies it. Together, Figures 31 and 27 demonstrate why technology-share reporting should eventually be supplemented by a unit-level concentration indicator, such as the maximum provider share or a Herfindahl–Hirschman Index calculated for each 15-minute interval.

Integrated system-level interpretation

The four days demonstrate that the value of flexibility is regime-dependent.

Under relative flexibility scarcity, as on 17 May, BESS and DR directly substitute conventional reserve provision, reduce natural-gas output and reduce thermal ramping.

Under storage-intensive conditions, as on 1 November, batteries combine energy shifting with reserve and congestion-management services. More services are provided without more battery throughput, demonstrating that service provision and energy cycling are not proportional.

Under congestion- and headroom-dominated conditions, as on 6 July, batteries provide large operational value despite almost no cycling. Natural-gas energy falls, but thermal ramping increases because the remaining online units must reposition more actively.

Under high absolute system scale, as on 21 January, the large committed gas fleet absorbs substantial reserve requirements, while BESS provide fast capacity with little energy movement. However, the reduced/full comparison is dominated by different BE inputs and should not be used as a direct causal estimate.

The results therefore do not support the simplistic conclusion that the full flexibility portfolio always reduces natural-gas production. A more accurate conclusion is that it redistributes flexibility obligations across technologies and across service layers. Its main value may appear as:

- lower conventional energy;
- lower conventional reserve provision;
- fewer committed gas units;
- reduced thermal ramping;
- greater congestion-management capability;
- lower storage cycling for the same service volume;
- improved access to fast and local flexibility.

The resulting multi-layer architecture is summarised in Figure 33. The figure aggregates the four full-flexibility days and shows each technology’s contribution to balancing energy, FCR, aFRR, mFRR, congestion management and FFR.

Figure 33 demonstrates that the full portfolio does not replace one dominant technology with another. Instead, it creates a specialised architecture:

- natural gas remains central to FCR and downward control;
- hydropower provides a disproportionate share of upward reserve and TSO congestion relief;
- TSO BESS contributes to system balancing, mFRR, TSO-CM and FFR;
- DSO BESS supplies local congestion management and its defined FFR shares;
- DR provides strategically valuable marginal flexibility in mFRR and TSO-CM.

This is the principal system-level result of the analysis. Coordination improves performance not through universal displacement of conventional resources, but through a more differentiated allocation of flexibility functions.

Overall conclusions

The analysis identifies four complementary findings.

First, system size and operational stress are not equivalent. The largest day, 21 January, is not the most constrained relative to available output. The smaller 17 May system has the highest relative flexibility stress.

Second, 17 May provides the strongest controlled evidence of flexibility substitution. With identical common requirements, 5.354 GWh of conventional reserve provision shifts to BESS and DR, accompanied by lower natural-gas generation, commitment and ramping.

Third, BESS value cannot be inferred from throughput alone. On 6 July and 21 January, large reserve and congestion-service volumes are supplied with minimal cycling. These batteries operate as fast capacity assets rather than energy-shifting assets.

Fourth, natural gas and hydro remain essential but increasingly specialised. Natural gas retains the principal role in FCR, aFRR Down and downward security. Hydro provides flexibility far above its energy contribution, especially in mFRR Up and TSO-CM Up. BESS and DR reduce the reserve burden on both technologies and add fast, bidirectional and local flexibility.

2.5.4.4 Results from TSO validation

The results derived from the balancing market DT are validated through power flow simulations on the actual topology of the transmission network that integrates all the network changes planned for 2030. The validation focuses on the transmission grid of Crete Island, which was recently strongly interconnected with the mainland grid and is expected to accept a large amount of new RES stations, battery units and the complete decommissioning of the conventional units.

The transmission power-flow model is solved for all evaluated time units using the DAM and BM schedules described in Section 2.3.3.3. Figure 35 illustrates a thermal-limit violation at 15:45 on 6 July 2030 in the reduced-flexibility configuration defined in Section 2.5.1.2. A transfer of 124.3 MW from Agia Varvara toward Linoperamata reaches 95% of the relevant overhead-line capacity, rendering the market schedule infeasible and triggering a corrective constraint for the next BM run.

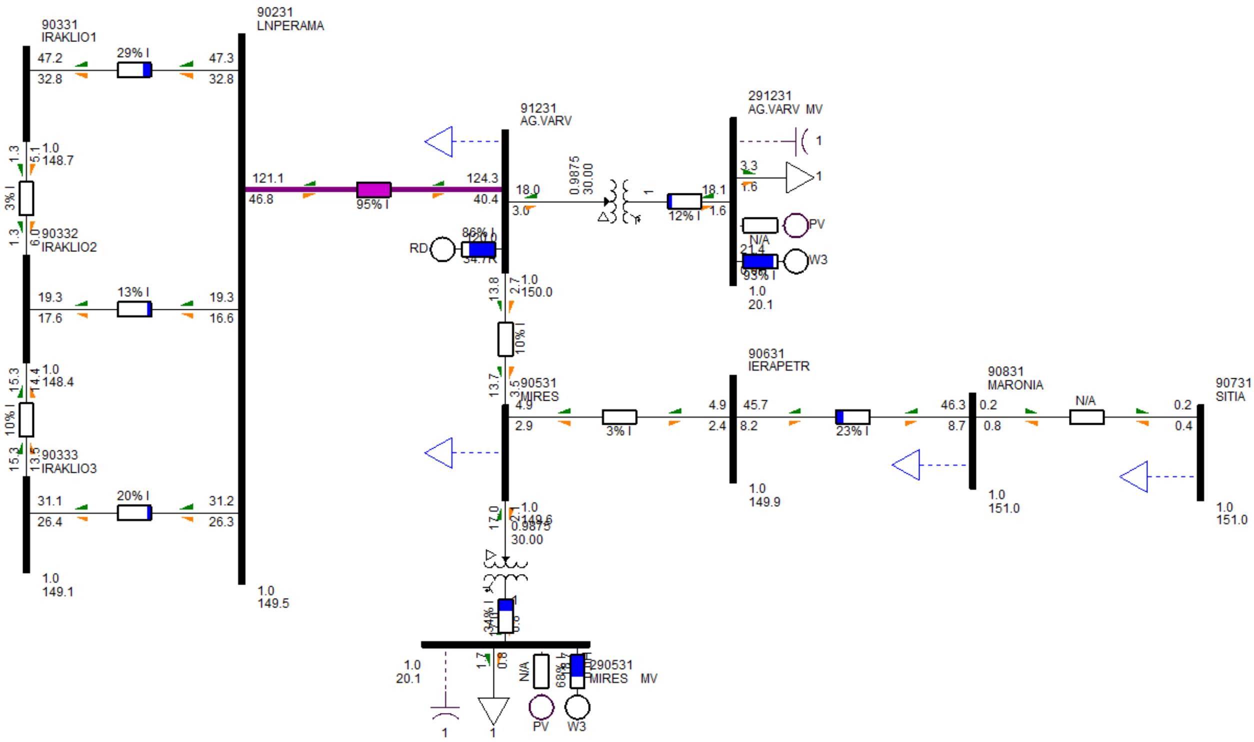


Figure 35. Power-flow solution for 06/07/2030 at 15:45 under the reduced-flexibility case.

Figure 36 presents the same time instant under the increased-flexibility configuration. Four BESS units connected at different Cretan substations reshape local power flows under identical load and RES conditions. No overhead line remains congested, and the schedule is technically feasible without additional redispatch.

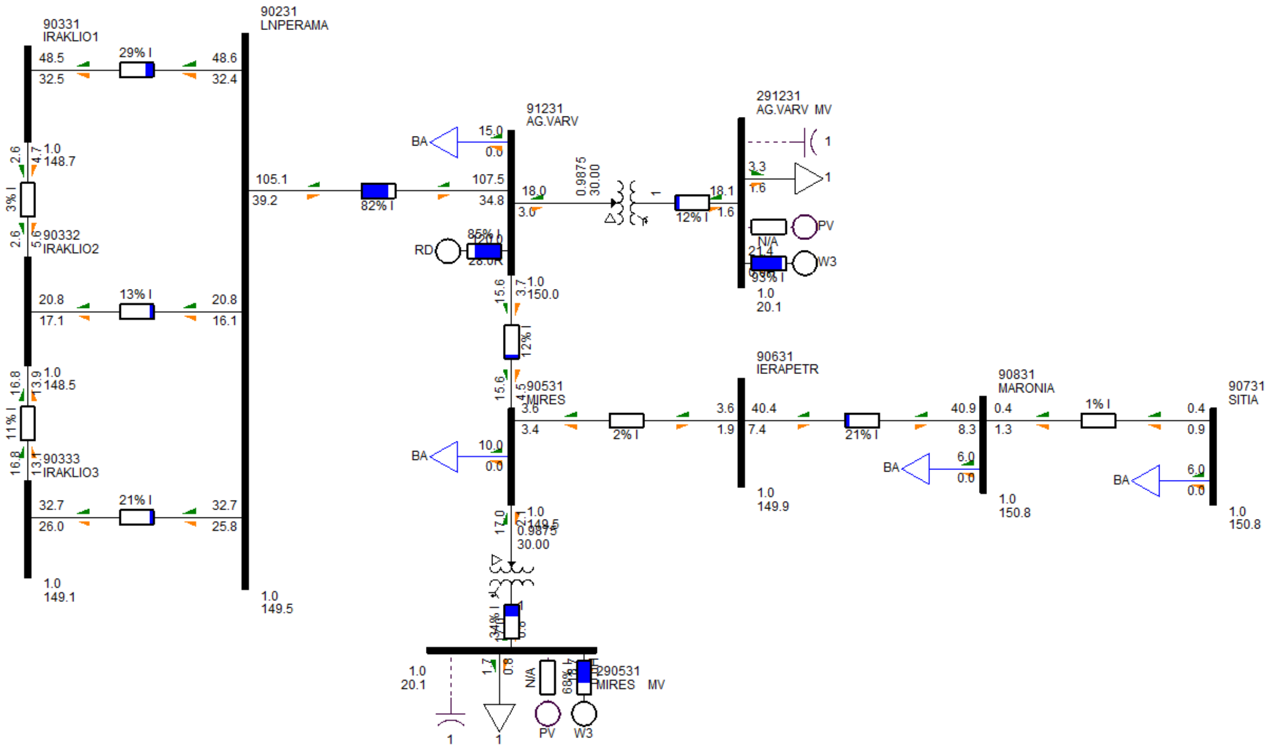


Figure 36. Power-flow solution for 06/07/2030 at 15:45 under the increased-flexibility case.

2.5.4.5 Results from DSO Grid Feasibility Validation

The DER activation schedules produced by the BM Simulator are validated through power-flow simulations on a representative MV feeder. Figures 37 and 38 compare the state-of-charge trajectories and validated BESS dispatch schedules under the increased-flexibility and baseline configurations.

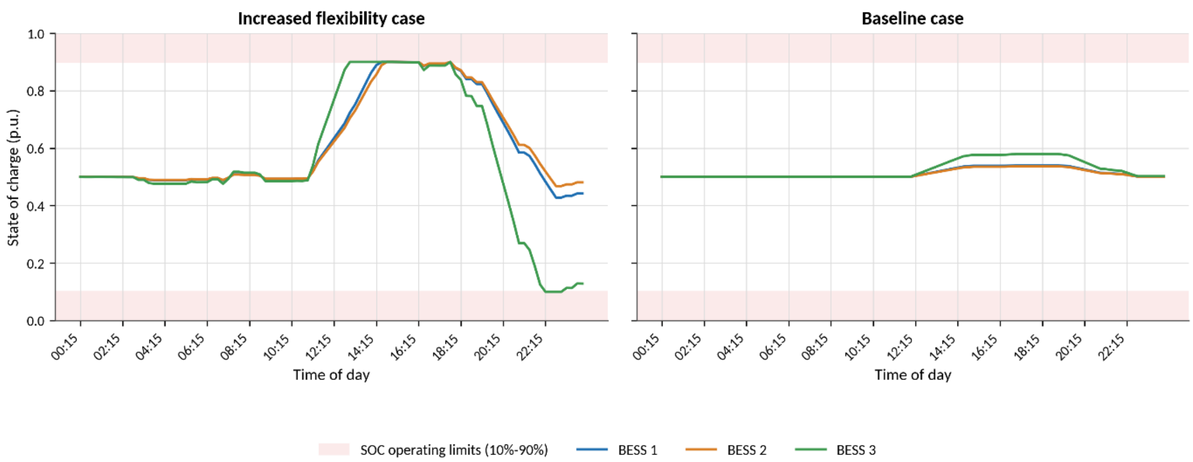


Figure 37. State-of-charge trajectories of the validated battery storage units under the increased-flexibility and baseline cases.

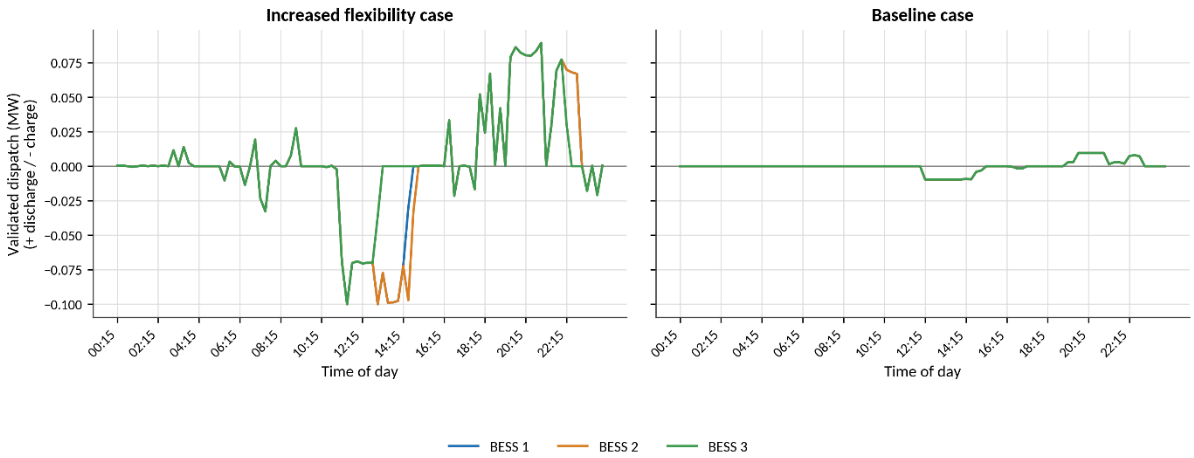


Figure 38. Validated dispatch schedules of the battery storage units under the increased-flexibility and baseline cases.

2.5.5 Summary of Grid Feasibility, Market Efficiency, and Flexibility Utilization

The Greek Demo provides an end-to-end demonstration of how a digital twin can connect market design, balancing-market operation and physical grid validation within a single analytical chain. Its main contribution is not one isolated optimisation result, but the establishment of a traceable workflow in which future market conditions are generated by the Day-Ahead Market Simulator, translated into balancing and reserve requirements, cleared through the Balancing Market Digital Twin, and subsequently challenged against transmission- and distribution-grid constraints. This progression from market outcome to operational schedule to grid-feasible dispatch is the defining achievement of the demonstration.

At the market layer, the Day-Ahead Market Simulator establishes a credible basis for forward-looking analysis. Its historical validation reproduces Greek market-clearing prices with low errors across all four representative days: the reported root-mean-square error ranges from 0.071 to 0.781 €/MWh, while the maximum absolute error remains between 0.59 and 3.40 €/MWh. This level of agreement is particularly important because the projected 2030 results are not generated from a stylised merit order detached from current market practice; they are derived from an extensively validated representation of the existing Greek Day-Ahead Market and then transformed through transparent scenario alterations.

The projected 2030 configuration materially expands the space available to renewable generation and flexible resources. Cleared DER transactions increase in every representative operating condition, with absolute gains ranging from approximately 49 GWh on the low-load, low-RES autumn day to approximately 77 GWh on the high-load, high-RES summer day. In relative terms, the increase ranges from 66.9% to 102.1%. These gains demonstrate that DER participation is not confined to one favourable seasonal condition: higher renewable availability and higher demand can both create additional market opportunities, albeit through different operational pathways.

The market transformation is accompanied by a substantial economic benefit. Total social welfare increases by 22.11%–27.37% across the four representative days. The benefit is observed under both high- and low-demand conditions and is driven predominantly by increased consumer surplus, as additional RES participation, storage operation and demand-side flexibility moderate high-price periods and improve the utilisation of lower-cost resources. Average market-clearing prices decline by 12.7% in autumn, 14.3% in winter, 55.8% in spring and 29.3% in summer. The results therefore provide strong evidence that a more flexible, renewable-rich system can produce significant welfare gains. At the same time, they reveal a crucial trade-off: lower average prices do not necessarily imply smoother prices. Spring and summer exhibit markedly stronger price dispersion, prolonged low or negative prices, and sharper evening transitions. Flexibility becomes more valuable precisely because the future market becomes more dynamic.

The balancing-market assessment reveals four clearly differentiated operating regimes. The winter day, 21 January, is the largest in absolute terms, with approximately 114.57 GWh of natural-gas production, 32.18 GWh of hydroelectric production, and more than 14 natural-gas units online on average. However, it is not the most constrained case relative to the size of its committed fleet. By contrast, 17 May has a much smaller conventional energy base but the highest relative pressure on available upward headroom. The 1 November case is characterised by intensive battery cycling and multi-service operation, whereas 6 July represents a headroom-dominated regime in which batteries provide substantial reserve, congestion-management and fast-response capability with very limited daily energy throughput. These are not small variations around a common operating pattern; they are structurally distinct balancing challenges.

The most defensible evidence of flexibility substitution is provided by the 17 May controlled counterfactual, because the reduced and full-flexibility configurations have identical common-product requirements and no BESS or demand-response provision in the reduced case. In that comparison, conventional FCR, aFRR and mFRR provision falls from approximately 32.36 GWh to 27.01 GWh, while BESS and demand response provide 5.354 GWh of time-aggregated reserve-capacity volume. The transfer is effectively one-for-one. It is accompanied by a 2.95 GWh reduction in natural-gas generation, a 0.56 GWh reduction in hydro generation, a decrease of 0.36 in the average number of online gas units, and a 5.4% reduction in gas-unit ramping. This is the clearest result in Deliverable 7.2 showing that distributed flexibility can reduce both conventional reserve provision and the operational burden placed on the conventional fleet.

The remaining days provide equally valuable, although methodologically different, insights. On 1 November, approximately 8.41 GWh of congestion-management and FFR capacity is added without increasing natural-gas generation and while battery throughput is actually lower than in the reduced configuration. The system obtains greater flexibility value from the available battery power capacity without requiring additional energy cycling. On 6 July, natural-gas generation decreases by 5.36 GWh and the average online gas commitment declines, but unit-level gas ramping increases by 23.3%. This demonstrates that lower thermal energy does not automatically mean less demanding thermal operation: when fewer units remain online, the surviving fleet may have to move more aggressively to support multiple services. On 21 January, the larger balancing-energy requirement dominates the difference between the two configurations; that pair should therefore be interpreted as a comparison of complete operating configurations rather than as a causal estimate of the effect of BESS, demand response or the additional services.

The results also reveal an increasingly specialised technology architecture. Natural gas remains indispensable for security-oriented products, particularly FCR, aFRR Down, downward regulation and much of TSO congestion management in the downward direction. Its role is therefore not eliminated by DER deployment; rather, it becomes more focused on synchronous capacity, stable operating margins and downward controllability.

Hydropower exhibits a different form of system value. Across the four full-flexibility cases, its share of mFRR Up is approximately twice its share of conventional energy production. It also provides a major share of upward TSO congestion management—approximately 59% on 6 July, 81% on 1

November and 83% on 21 January. Hydropower should therefore not be assessed solely by the energy it generates. Its disproportionate contribution to upward reserve, rapid redispatch and congestion relief makes it one of the most valuable flexibility assets in the portfolio.

Battery value is similarly multidimensional. On 1 November and 17 May, batteries operate as both energy-shifting and ancillary-service resources, with throughput of approximately 16.44 GWh and 14.12 GWh, respectively. On 21 January and 6 July, throughput is only approximately 0.14 GWh and 0.17 GWh, yet batteries still provide large quantities of reserve and congestion-management capacity. These low-throughput cases are not examples of underutilisation. They demonstrate a fundamentally different storage function: batteries act as fast capacity and headroom assets, maintaining the ability to respond in either direction while transferring little net energy. Any assessment based only on charging and discharging volumes would materially understate this contribution.

Demand response contributes smaller absolute volumes but has high marginal value. Its importance is greatest when a limited quantity of rapid load flexibility avoids the commitment, repositioning or reserve withholding of an additional generating unit. Its contribution should therefore be interpreted in terms of the conventional capacity and operating margin it releases, not only the energy volume it activates.

Fixed pumping schedules add another important methodological lesson. Where pumping-unit mFRR Down participation is treated as a validated exogenous schedule, that contribution is credited before the remaining requirement is optimised. This prevents double procurement and preserves consistency with the observed ISP outcome. At the same time, fixed schedules can exceed the original requirement in individual periods. Such overcoverage is not a solver imbalance; it is a direct consequence of preserving an exogenous schedule. Transparent reporting must therefore distinguish the original requirement, fixed pumping contribution, non-negative residual requirement, optimised residual provision and any fixed overcoverage.

The findings further demonstrate that daily diversification is not equivalent to operational robustness. A model may reproduce the intended daily technology shares while concentrating a service in one provider during individual 15-minute intervals. In the assessed mFRR Up results, the maximum contribution of one provider reaches approximately 88.8% on 6 July, 81.3% on 1 November, 68.4% on 17 May and 42.9% on 21 January. For mFRR Down, one provider supplies the complete optimised requirement in some intervals on three of the four days. Daily technology shares, interval-level provider counts and unit-level concentration must therefore be reported as separate indicators. A portfolio that appears diversified at daily level may still be exposed to a critical single-provider dependency.

The transmission-grid validation provides compelling physical evidence of the value of coordinated flexibility. In the 6 July baseline case at 15:45, the transfer from Agia Varvara toward Linoperamata reaches 124.3 MW, corresponding to 95% of the overhead-line capacity, and the market schedule is classified as technically infeasible. When the increased-flexibility configuration is assessed under the same RES and load conditions, four BESS units positioned at different Cretan substations reshape the local power flows. The line congestion disappears and no further redispatch is required. This result moves the argument beyond an abstract reduction in system cost: it shows that the spatial deployment of flexibility can turn an infeasible market schedule into a feasible network operating point.

The distribution-grid validation reaches an equally important conclusion. Three battery units are dispatched over every 15-minute interval on a representative MV feeder. In the increased-flexibility case, the most heavily used battery moves from its 90% upper state-of-charge limit to its 10% lower limit, demonstrating substantial operational use. Nevertheless, feeder voltages remain approximately within 0.96–1.00 p.u., the most heavily loaded line reaches only 59%, and the most heavily loaded transformer reaches 53%—comfortably within the adopted voltage band of 0.90–1.10 p.u. and the 95% equipment-loading threshold. No battery activation requires curtailment or rejection. The result confirms that significant distribution-connected flexibility can be physically accommodated in the studied feeder when its dispatch is validated against local constraints.

Together, the transmission and distribution results define the practical meaning of TSO–DSO coordination in the Greek Demo. Coordination is not merely the exchange of forecasts or the aggregation of two requirements. It is the capacity of the market layer to produce a schedule, of the grid tools to challenge that schedule, and of the optimisation layer to revise it when the physical system rejects it. The market optimiser, TSO power-flow model and DSO prequalification tool therefore form a feedback-driven decision process in which economic efficiency is accepted only after technical deliverability has been demonstrated.

The evidence must nevertheless be interpreted within clearly stated boundaries. Only the 17 May pair is a fully controlled counterfactual; the other three pairs contain differences in common-product requirements or reduced-case BESS and demand-response participation. The simulations are deterministic, the balancing formulation does not embed a complete nodal AC network model, and the current module interfaces remain partly manual or semi-automated. Storage is aggregated in the balancing model, while more detailed state-of-charge behaviour is assessed in the DSO tool. These limitations do not invalidate the findings, but they determine which conclusions can be stated causally and which should be presented as configuration-level observations.

The overall finding is therefore both ambitious and defensible: the Greek Demo shows that a renewable-rich 2030 electricity system can achieve higher DER participation, higher social welfare and technically feasible balancing operation—but only when flexibility is treated as a locational, time-dependent and multi-service capability. The value of the digital twin lies precisely in making those dependencies visible before they become operational risks.

3 Hungarian Demonstration

3.1 Purpose, Scope, and Demonstration Context

3.1.1 Purpose and ambition of Task 7.3

Task 7.3 establishes and demonstrates an integrated workflow for the coordinated treatment of short-term energy trading, balancing capacity procurement and transmission-capacity calculation in the TwinEU Hungarian use case. It aims not to replace the legally binding European market-coupling and system operation processes, but to reproduce their technically relevant elements in a controlled and adaptable environment. The task therefore translates real operational concepts, data structures, interfaces and timing requirements into a software-supported workflow that can be executed repeatedly, compared across scenarios and assessed without creating financial, contractual or system-security consequences.

The ambition is to show how a market platform can be operated when energy-market orders, balancing capacity requirements and network constraints shall be handled consistently across several market timeframes. The demonstration combines three main areas of interest: dynamic line rating (DLR), flow-based capacity calculation (FB CC) and market co-optimisation. These are treated as connected components of one workflow rather than as isolated analytical exercises. DLR modifies the technical transfer capability of selected network elements; the capacity calculation process translates the updated grid state into cross-zonal constraints; and the market algorithm uses those constraints together with energy and balancing capacity bids to determine feasible market outcomes.

3.1.2 Demonstration concept and technical scope

The work builds on the prototype concepts developed in the FARCROSS project, adapting them to the TwinEU Hungarian demonstration and increasing the maturity of the integrated solution. The objective is reproducibility and operational relevance rather than the creation of an entirely new European market architecture. Consequently, the demonstration applies the logic of established market processes: bid collection and aggregation, preparation of network constraints, gate closure, market-coupling calculation, result validation, publication, and transfer of updated information to the next market period or auction (i.e., the day-ahead or intraday timeframe) or to the next capacity-calculation step.

The software implementation is designed around formats, time resolutions and information flows equivalent to those used in operational practice. Energy-market data, balancing-capacity data, cross-zonal capacity data and flow-based parameters are processed according to the logic required by market operators, TSOs and EU-wide market-coupling operators. HUPX Labs provides the common environment for data exchange, integration, result storage and visualisation, while the market-auction and optimisation components reproduce the core functions of order-book management and market coupling. Although the demonstration goes beyond a conceptual simulation, it remains a non-operational parallel dry-run environment: participants' individual market positions, allocations, physical and financial nominations, clearing, settlement and any legally or financially binding outcomes remain outside its scope.

The following subtasks divide the integrated workflow among the principal implementation partners. HUPX specifies the auction-based market design, data flows and platform requirements; MAVIR describes the Hungarian balancing-capacity market and the transmission-capacity calculation process; BME conceptualises the complete workflow and integration, implements the optimisation-algorithm concepts and validated mathematical models, develops the scenario framework and contributes to the market-auction platform; and Artelys develops and consolidates the co-optimised market-clearing solution and its supporting capacity-calculation components. The interfaces between these contributions are essential because each run can be reproduced only when input ownership, file structures, timing, validation rules and output responsibilities are unambiguous.

3.1.3 Regulatory and market-design context

The demonstration is aligned with the European regulatory framework governing the short-term operation of day-ahead and intraday electricity markets. The Capacity Allocation and Congestion Management (CACM) framework provides the basis for coordinated capacity calculation and the coupling of day-ahead and intraday markets [29], [30]. Single Day-Ahead Coupling (SDAC) and Single Intraday Coupling (SIDC) define the European market-coupling processes and their associated auction optimisation. EUPHEMIA is the algorithmic reference for pan-European auction-based price coupling [7]. The Electricity Balancing Guideline (EBGL) provides the conceptual basis for balancing products, balancing-capacity procurement and interactions between Balancing Service Providers (BSPs) and TSOs [31], [32], [33], [34]. The ALPACA cooperation provides a practical example of cross-border balancing-capacity procurement and coordination among participating TSOs.

In the demonstration, market co-optimisation means that energy and balancing-capacity bids are considered within a coordinated clearing problem rather than procured through completely independent sequential calculations [35], [36]. The approach seeks a feasible allocation that respects the relevant energy balances, reserve requirements, order characteristics and transmission constraints while maximising the selected welfare objective. In the TwinEU demonstration, this concept is applied to day-ahead and intraday auctions and can be combined with updated capacity information between successive auctions. The detailed mathematical formulation and supported order types are presented in the market-algorithm section.

The implemented DLR methodology and subsequent flow-based capacity calculation extend the network constraints applied in the demonstration. Conventional line ratings are based on static assumptions, whereas DLR allows the admissible loading of selected lines to be adjusted according to measured or forecast environmental and thermal conditions [37], [38]. The resulting capacity values are translated into Remaining Available Margins and other flow-based parameters used by the market-coupling calculation. This creates the central link between changes in physical grid capability and their effects on congestion, balancing-capacity procurement, market prices and accepted volumes.

3.1.4 Development of the Demonstration

The implementation environment has evolved since the proposal was prepared, as European market integration continues to progress [39]. The demonstration must therefore represent a more detailed intraday sequence, including several intraday auctions (IDA1, IDA2 and IDA3) and the capacity-calculation updates that precede them. In parallel, the European market environment has moved towards a 15-minute Market Time Unit, including the transition of the day-ahead market from hourly to quarter-hourly resolution. This change affects the structure and volume of input data, product definitions, the number of optimisation intervals, and the time available for data preparation, calculation and validation.

Data availability and transparency have also proved more constraining than anticipated, despite regulatory ambitions for harmonised EU-wide transparency, access and operator accountability. Inputs originate from partner systems, NEMOs, the ENTSO-E Transparency Platform, the JAO Publication Tool and other public or project-specific datasets. Their formats, naming conventions, time zones, aggregation levels, publication schedules and revision practices are not uniform. Compared with the earlier FARCROSS prototype environment, the TwinEU workflow therefore requires more extensive data mapping, harmonisation and quality control before the datasets can be used together. Although overall data availability has improved, the absence of common data-management arrangements, technology-agnostic connectors and consistent update and publication practices creates substantial friction for quantitatively robust electricity-market research and development. Where confidential operational data cannot be distributed, anonymised, aggregated or publicly available substitutes are used and their limitations are documented.

These challenges did not hinder the principal ambition of the task, but they influenced how the demonstration was implemented. The resulting solution places greater emphasis on configurable interfaces, quarter-hourly time series, repeatable import and validation procedures, and explicit fallback rules for incomplete or inconsistent data. It also requires a clear distinction between the functions reproduced in the demonstration and those that remain outside its scope. In particular, the project reproduces the technical sequence needed to generate and validate market outcomes, but not the complete operational-governance framework, incident-management obligations, settlement processes or allocation of legal responsibility.

3.1.5 Task coordination and project management approach

Task coordination must ensure that the work of the market, system-operation, data-platform and optimisation partners converges into one executable process. The coordination cycle therefore starts with a common specification of the demonstration cases and the required inputs and outputs. For each dataset, the responsible partner identifies the source, owner, temporal coverage, resolution, unit, format, access restrictions and expected update frequency. The receiving partner then documents the transformation needed for its model or software component. This interface-oriented approach is necessary because a technically correct local model can still fail at integration if time stamps, bidding zone identifiers, sign conventions, product definitions or file versions are interpreted differently.

The integrated work should proceed through iterative implementation and validation rounds. First, the partners agree on the minimum viable end-to-end workflow and test it with a limited dataset. Second, the individual components are expanded to support the required order types, capacity calculation variants, DLR cases and day-ahead or intraday timeframes. Third, the scenario matrix is executed, and the outputs are checked jointly against source data, expected market logic and physical constraints. Issues identified during a run are assigned to the partner responsible for the relevant data or software component, and corrections are retested in the same scenario so that the effect of each change remains traceable.

The main coordination challenges are data transparency, confidentiality, changing external platforms, heterogeneous formats and the alignment of several operational timelines. The availability of NEMO data and the accessibility of ENTSO-E Transparency Platform information can limit the completeness of international bid curves. Capacity data and market data may be published at different resolutions or may be revised at different times. DLR inputs have their own forecast horizon, while capacity calculation and auction gate closures impose strict deadlines. These constraints require documented assumptions, controlled versions of input files and a clear rule for selecting the latest valid dataset for each simulation run.

A further management requirement is to maintain a shared boundary between demonstration realism and project feasibility. The workflow should preserve the essential sequence, data dependencies and validation checks of the real process, but it must not introduce activities that cannot be supported by the available data or that would imply operational responsibility. Decisions on simplification, data substitution or deemed acceptance should therefore be recorded together with their rationale and expected effect on the results. Partner review is particularly important for assumptions concerning national market rules, capacity calculation parameters and the interpretation of confidential or aggregated data.

3.1.6 Expected outputs and link to the following subtasks

The output of Task 7.3 is a documented and reproducible demonstration workflow linking data provision, flow-based capacity calculation, market clearing, scenario execution and result evaluation. The following sections reflect the contributions of the original subtasks while presenting them according to the final structure of the deliverable. Subtask T7.3.2 is covered through the description of the energy-market design, auction sequence and data flows supported by HUPX Labs. Subtask T7.3.3 addresses the balancing-capacity market design and the associated datasets, while Subtask T7.3.4 presents the flow-based capacity-calculation process and its DLR extension. Subtask T7.3.5 integrates these elements into the scenario design, workflow and execution framework, and Subtask T7.3.6 describes the market-clearing and co-optimisation solution. The subsequent simulation-results section evaluates the implemented scenarios and reports the corresponding KPI outcomes. Together, these sections document how the demonstration was implemented, which inputs and assumptions were applied, which functions were reproduced, and what technical and market effects were observed across the evaluated capacity-calculation and market-design variants.

3.2 Energy Market Design and Data Flows with Co-Optimisation Extension

This section presents the energy-market design and data-exchange framework applied in the Task 7.3 demonstration. It describes the entities, interfaces, auction phases, timing requirements, order types and information flows required to reproduce the technically relevant elements of European day-ahead and intraday auction-based market coupling. Particular attention is given to the use of HUPX Labs as an existing proprietary HUPX platform operating in an industrial NEMO environment. The platform was not developed within TwinEU; it is used as the data-exchange, integration, result-storage and visualisation environment around which the project-specific capacity-calculation and market-clearing components are connected.

3.2.1 Entities

TSOs: The Entity TSOs is an abstraction of all individual TSO local systems together with all TSO regional systems.

CORE CCR: Core ID Capacity Calculation (IDCC) is performed by the ID module of Core CC Tool (CCCt) for all Core internal borders (and potentially some Core external borders). CCCt is the main interface between Core TSOs and XBID CMM regarding IDAs. Individual TSOs are connected to CCCt to provide input data needed for the pre-coupling or receive Market results and rights (from IDA) in the post-coupling.

NEMOs: The Entity NEMOs is an abstraction of all individual NEMO pre-coupling, coupling and post-coupling systems.

Shipping systems: Shipping systems are facilitated by NEMOs in all areas except for CZ, HU, SK, RO, where this is done by the TSOs.

XBID: the system responsible for continuous ID market and during the IDA pre-coupling for CZC reception from TSOs and CZC submission for CIP and result validation

PMB/Euphemia: The Entity PMB/Euphemia represents the set of PMB instances as represented by the broker cloud, which jointly run an IDA. EUPHEMIA is an algorithm that solves the market coupling problem.

IDA – CIP: The Entity Central Interface Point represents intermediary functions between XBID (CMM) and NEMOs

3.2.2 Interfaces

1. TSOs – XBID: This is the interface for information exchange between the TSO systems and the CMM of XBID.
2. CORE CCR: CCCt will retrieve regularly AAC for all Core internal borders from XBID CMM in order to calculate the capacity (ID ATC extraction and NTC computation). CCCt will provide NTCs (and DA AAC for IDA1) for all Core internal borders.
3. TSOs – NEMOs: This is the interface for information exchange between the TSO systems and NEMOs local systems for nomination and scheduling purposes.
4. NEMOs – PMB/Euphemia: This is the interface that the NEMOs use to exchange trading data information with PMB/Euphemia.
5. XBID – CIP: This is the interface for information exchange between the XBID and CIP.
6. NEMOs – CIP: This is the interface for information exchange between the CIP and NEMOs local systems.

3.2.2.1 XBID integration

- TSOs provide network constraints to XBID CMM
- Communication between XBID and PMB/Euphemia to exchange network constraint data before the auction and IDA results and its validation after the auctions is performed via IDA CIP and NEMOs.
- Initial AAC for first IDA would be sent by TSOs to XBID CMM before IDA1
- Updates of NTC before auctions IDA2, IDA3 would be sent to XBID CMM by TSO/CCC before the IDA2 IDA3
- No handling of net positions, prices and NTH flows by XBID
- Handling of IDA results (flows per border) integrated in XBID CMM, technically as explicit allocations.
- IDA post-coupling (nomination) data by XBID SM module

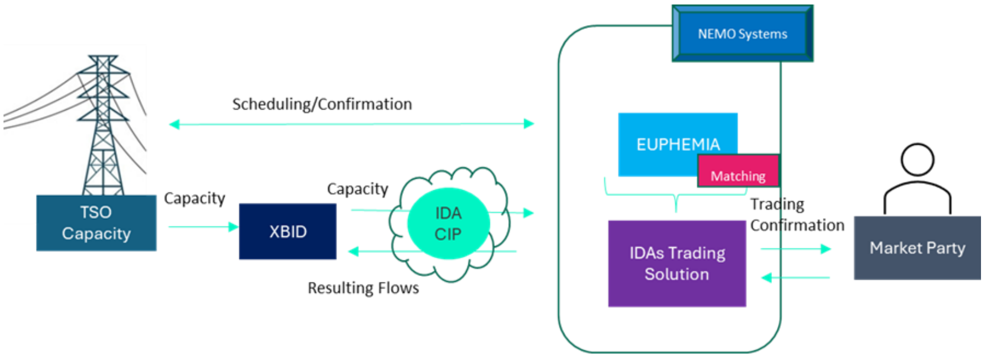


Figure 39. Entities and principal interfaces of the intraday auction process.

3.2.3 Phases

IDAs can be split up into three phases:

1. Pre-IDA phase where input for the IDA is collected and submitted (also called “pre-coupling”)
2. IDA phase, where the IDA is run and the results are validated (“coupling”)
3. Post-IDA phase, where firm output of the IDA is submitted and processed. (“post-coupling”)

3.2.3.1 IDA Phase I (Pre-IDA)

1. XBID cross-border trading halted: XBID borders are switched automatically to “halt” status 20 minutes before the IDA gate closure time. For borders to which ramping restrictions apply, the last hour preceding the contracts included in the relevant IDA is also halted. XBID automatically suspends both implicit and explicit cross-border trading.
2. Download XBID Allocations: The XBID AACs are downloaded by the TSOs as input for the calculation or update of the ID NTC/ID FB Domain by TSOs prior to each IDA.
3. Calculate ID NTC/FB domain:_CCCt will extract ID ATC from the relevant FB Domain, starting from the last available AAC (DA AAC + IDAx/IDC AAC). ID NTC will be calculated as ID ATC+last AAC. When IDA will be in FB, the FB parameters will be enough without need of ID ATC extraction.
4. Send NTC/Flow-based domain: TSOs/CCCt upload(s) the NTCs or FB parameters (RAM, PTDF) in case of FB allocation to XBID CMM.
5. Send IDA network data from XBID to CIP: This flow contains the relevant CZCs and allocation constraints for running of the IDA (Total AAC and ATC, Allocation Constraints). Allocation constraints involve ramp rates, net position allocation constraint and last MTU flows as well as loss factors.
6. Network data preparation_This step ensures preparing the XBID output data for download by NEMOs
7. Download IDA network data:_This flow contains the relevant CZCs and allocation constraints for running of the IDA (Total AAC[1], and ATC[2] , Allocation Constraints) in PMB format
8. Publish offered capacity for IDA:_TSOs are obliged to publish offered capacity for IDA at ENTSO-E Transparency Platform. This obligation is fulfilled via XBID

3.2.3.2 IDA Phase II (IDA coupling)

1. Send IDA network data: NEMOs forward the IDA network data they received from the CIP to PMB/Euphemia.

2. Cross-check IDA network data: PMB/Euphemia cross-checks the IDA network data received. If the same data have been submitted through several NEMOs, it has to be ensured that the total set is consistent.
3. Aggregate order books: NEMO trading systems create aggregated order books on the basis of the IDA orders they received from their market participants.
4. Send aggregated order books: The NEMOs submit the aggregated order books to PMB/Euphemia.
5. Calculate IDA results: PMB/Euphemia calculates the IDA results on the basis of the IDA network data and the aggregated order books. The IDA results comprise prices per bidding zone, total scheduled flows per interconnector, net positions per bidding zone, NEMO net positions per NEMO Trading Hub, flows between NEMO Trading Hubs. If applicable (FB), they also contain shadow prices.
6. Send IDA results: PMB/Euphemia submits the IDA results to the NEMOs.
7. Check IDA results: The NEMOs check the IDA results against the order books (portfolio allocation).
8. Process NEMO confirmations: PMB/Euphemia generates a global preliminary confirmation based on the (positive) preliminary result confirmation of all NEMOs.
9. Send IDA Results: NEMOs send IDA results in PMB format to CIP
10. IDA results transformation and selection: This step ensures transformation of PMB NEMOs output format to XBID input formats and filters out all result data except the IC flows

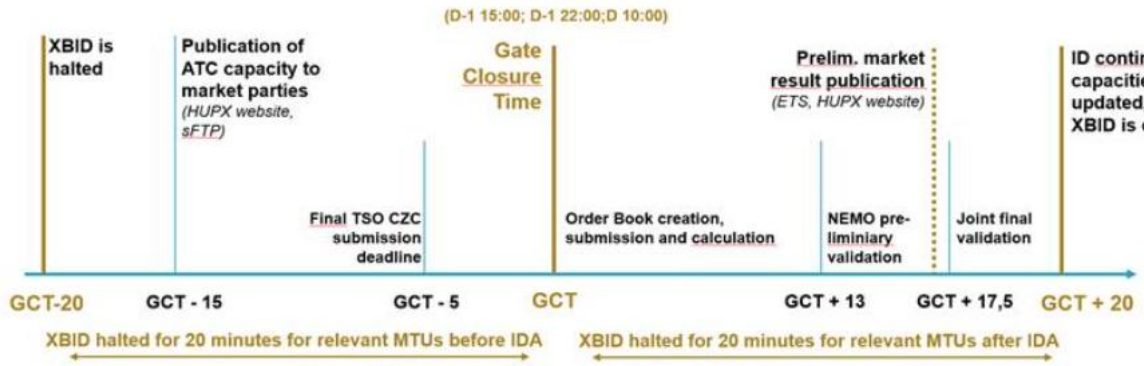


Figure 40. Intraday-auction process sequence and operational timing.

3.2.3.3 Responsibilities and Functions

TSOs are responsible for the following functions:

- Individual grid analysis and coordinated capacity calculation
- Provision of the capacity data necessary for the operation of MC

Out of the scope of the demonstration:

- Scheduling management: the reception of cross-border flows, internal nominations and transmission of nominated cross-border flow
- Physical and financial settlement of cross-border flows depending on the entity – i.e. energy shipping
- Congestion Revenue Calculation and Distribution (invoicing and settlement)
- Publication according to the European and the national legislation

PXs have to provide a trading platform to their market participants, and a variety of compatible order types with the matching algorithm.

MOs are responsible for the following functions:

- Collect the bids from market participants, transform them (aggregate and anonymize) - Perform price-coupling calculation and validation
- Mutually sharing the anonymized supply/purchase aggregated curves and block bids and outputs with protecting the necessary confidentiality
- After the coupling, the aggregated results are split to the individual bids according to calculated Net positions of each bidding zone and its clearing price.

Out of the scope of the demonstration:

- Allocate the individual results to the market participants and the local shipper
- Local hub nominations (one or two-sided, up to the local design)
- Individual trades are cleared and settled by the respective PXs in the relevant market areas, and the required information is published in accordance with European and national legislation. The agreed governance arrangements also influence the IT architecture of all parties.

3.2.3.4 Proposed Daily Demonstration Routine

The following describes the proposed daily routine for an auction conducted on day D or day D−1, as applicable.

3.2.3.4.1 Pre-coupling

- TSOs are solely responsible for providing cross-border capacities to the HUPX Labs Platform. The capacities must be transmitted to the PXs through the dedicated communication channel no later than 09:55 on day D, 14:55 on day D−1 for IDA1, and 21:55 on day D−1 for IDA2.
- Cross-zonal capacities (CZCs) are published on the HUPX Labs Platform at 09:45, with updates permitted until 09:55. For IDA1 and IDA2, the corresponding publication times are 14:45 and 21:45 on day D−1, respectively.
- Meanwhile, intraday market operators (MOs) verify the following:
    - the format of the received CZC data is suitable for publication.

  If data cannot be uploaded by the applicable deadline for a pan-European IDA, an incident call should be initiated to verify the availability of linear and block bids and the settings of the relevant trading systems, including the trading date and order-book availability. Because the activity is a demonstration, deadlines may be extended where necessary to resolve technical issues.

- Energy orders may be submitted from 45 days before the Delivery Day until the relevant order-book closure: 10:00 on day D, 15:00 on day D−1 for IDA1, and 22:00 on day D−1 for IDA2.

MOs are responsible for verifying that the order book is closed by the applicable deadline.

3.2.3.4.2 Coupling

- At gate closure, the pre-coupling phase ends and the coupling phase begins.
- After the order book has closed, orders cannot be entered, modified or cancelled.
- MOs upload the IDA order books to the HUPX Labs Platform.

- All required data, including anonymised aggregated supply and demand curves, are shared and downloaded by the MCO for calculation by 10:06 on day D, 15:06 on day D−1 for IDA1, and 22:06 on day D−1 for IDA2.
- The allocated time for order book creation and submission is 6 minutes.
- At the target time, the MCO runs the latest version of the intraday market-coupling auction algorithm and matches capacities and orders. The calculation must be completed by 10:14 on day D, 15:14 on day D−1 for IDA1, and 22:14 on day D−1 for IDA2 [40].

  The allocated calculation time for EUPHEMIA is seven minutes.

- After the market results have been calculated, the result-confirmation phase begins:
  - All required data are shared through HUPX Labs so that the MOs can verify the preliminary results and confirm that the complete result set has been received.
  - Preliminary Confirmation / Global Preliminary Confirmation: MOs validate the preliminary market results sent by the MCO by 10:17:30 on day D, 15:17:30 on day D−1 for IDA1, and 22:17:30 on day D−1 for IDA2.

    MOs verify that the calculated cross-border flows are consistent with the CZC data previously provided by the TSOs through the dedicated communication channel.

    Preliminary confirmation is outside the scope of the demonstration; only the final-confirmation phase is applied.

- TSO Confirmation / Final Confirmation / Global Final Confirmation: following confirmation by the MOs, the TSOs validate the results by 10:20 on day D for IDA3, 15:20 on day D−1 for IDA1, and 22:20 on day D−1 for IDA2.
- A positive Global Final Confirmation signifies that the pre-coupling and coupling stages have been completed and that the results are firm.
- *Generation of the Final Confirmation is outside the scope of the demonstration; deemed acceptance is applied.*

3.2.3.5 IDA Phase III (Post-IDA)

- After calculation and confirmation, the coupling phase ends and the post-coupling phase begins. MOs reopen the order book as soon as possible after publication and communicate the auction results to participants.
- Market results are published on HUPX Labs as soon as possible after 10:20 on day D for IDA3, 15:20 on day D−1 for IDA1, and 22:20 on day D−1 for IDA2.

The cross-border nomination is out of scope of the demonstration.

3.2.3.5.1 Data exchange – proposal

HUPX Labs serves as the primary data-exchange and integration interface for the simulation inputs, outputs and supporting source datasets used in the demonstration. It is an existing proprietary HUPX platform used in an industrial NEMO environment and was not developed as part of the TwinEU project. Within Task 7.3, the platform is used as an established technical component of the integrated demonstration workflow.

The relevant datasets are maintained in a structured form, with access controlled according to user permissions and data-confidentiality requirements. Data can be retrieved through GET API requests and made available in several formats, including XML and JSON. The platform is hosted in a cloud-based Microsoft Azure environment.

HUPX Labs is used to receive and organize selected market and network input data, store the results of the simulation runs and support the visualization of the evaluated scenarios. The project-specific development therefore concerns the integration of the capacity-calculation, market-clearing and result-processing components around the existing HUPX Labs environment, rather than the development of the platform itself. Using an industrially applied NEMO data platform as part of the end-to-end demonstrator strengthens the operational relevance of the integrated solution and supports the targeted increase in technology readiness.

The following figure presents the main data flows between the participating systems and organisations, focusing on the key elements of the Task 7.3 simulation workflow.

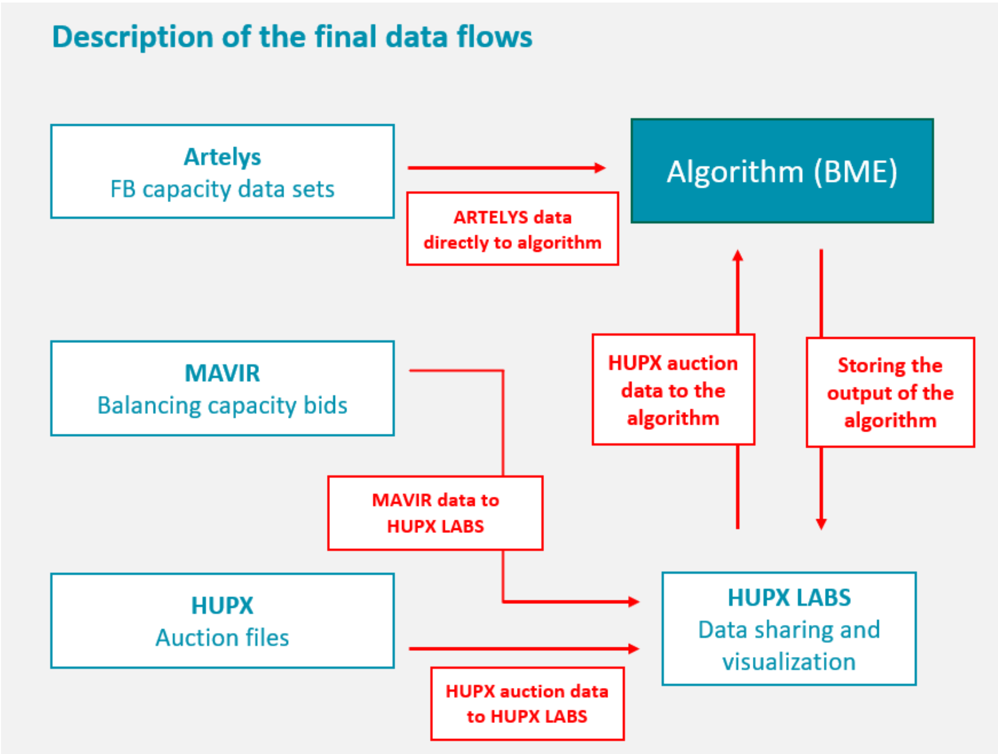


Figure 41. Data flows between HUPX Labs and the demonstration components.

3.2.4 TSO Data Flows to the HUPX Labs Platform

TSOs calculate the available transfer capacities and allocation constraints. The capacity is calculated with a 15-minute resolution. TSOs send the capacity files directly to HUPX Labs Platform.

3.2.4.1 MO Data Flow to the HUPX Labs Platform

All MOs collect locally with their own system the bids offered by their own market participants, bids which then are anonymized and aggregated in an Order Book file.

3.2.4.2 Data Flow from HUPX Labs to the Market Coupling Operator (MCO)

Once network and order book data are sent by each MO, Market Coupling Operator has all the necessary inputs to calculate market-coupling results (Network Data, Order Book, and fixed topology). MCO shall download all necessary data for the optimised market calculations.

3.2.4.3 Market Coupling Operator (MCO) Data Flow to HUPX Labs

MCO shall upload the market coupling results to the HUPX Labs Platform. BME has designed an order book management tool (market auction platform) and will be responsible for the MCO function with the contribution of Artelys.

3.2.4.4 Data Flow from HUPX Labs to Market Operators

MOs access their respective market results through the HUPX Labs Platform. The results are generated by the market-coupling calculation and may be checked by each MO, including prices and volumes per Market Time Unit and flows per border.

Portfolio allocation assigns an execution status—rejected, partially accepted or fully accepted—to each individual order and maps the aggregated market results back to participants' portfolios. Portfolio allocation is outside the scope of the demonstration.

3.2.5 Specific Requirements

The following requirements are extracted from the applicable algorithm methodology and summarise the principal rules governing pan-European Intraday Auctions [41], [42].

3.2.5.1 Mandatory Order Types

3.2.5.1.1 Linear curves (quarter-hourly orders)

Results for linear orders in the HUPX Intraday Auction Market are determined according to the following principles:

a) one market-clearing price is determined for each quarter-hourly product and each SIDC/IDA session;
b) the market-clearing price determines the cleared volumes in HUPX members' portfolios;
c) the cleared volume is determined by linear interpolation at the intersection of the clearing price and the order curve.

3.2.5.1.2 Block Orders

Simple

Block orders are all-or-none products with a minimum acceptance ratio of 1. They cover at least two consecutive contracts whose acceptance is linked in time [44], [45]. Each block order has one price. Regular block orders specify the same quantity for every contract in the block, whereas profiled block orders may specify different quantities by contract. Out-of-the-money block orders must be rejected. A paradoxically rejected block is rejected even though its price would otherwise satisfy the market-clearing condition.

Smart blocks

Linked Block Orders

- Linked Family of Block Orders
  Block orders may be linked through parent–child relationships. A child block can be accepted only if its parent block is accepted. The parent may be accepted even when it is individually out of the money, provided that the linked family is economically feasible as a whole. A

terminal child block, i.e. one with no linked children of its own, cannot be accepted out of the money.

– Loop blocks

  Loop blocks comprise two classic profiled blocks—for example, one sell block and one buy block—that are either both accepted or both rejected.

Block orders in an exclusive group

An exclusive group comprises block orders with an acceptance ratio of 1 in the Hungarian market; at most one order in the group can be accepted. Among the valid combinations, the market-coupling algorithm selects the one that maximises social welfare.

3.2.6 Requirements regarding Market Coupling Auction Platform

For each bidding zone, the Market Coupling Auction Module must support the following functions [43]:

- Intraday-auction cross-zonal gate-opening and gate-closure times (IDCZGT) must be configurable.
- The platform must support all MTUs from the first auctioned MTU to the end of the Delivery Day for each auction, following a "run-or-cancel" principle; decoupling procedures are not applied because of the applicable time constraints.
- An IDA is cancelled if results cannot be published by the applicable publication deadline.

3.2.6.1 Data Publication

The following market results are published on the HUPX Labs Platform:

- Date of the auction
- Date of delivery
- Market area
- Market messages
- Market clearing prices
- Volumes

3.2.6.2 Harmonisation of Market Characteristics

The core market-coupling principles and characteristics must be harmonised among participating parties and markets in accordance with the methodologies developed under the CACM Regulation. This includes harmonisation of timing (gate-closure times, publication of capacities and results, and nomination deadlines), data formats (communication interfaces and standardised file types), and value formats (decimal precision, minimum and maximum prices and volumes, tick size, price step and rounding) [46], [47], [48].

Table 12. Harmonised market characteristics of the intraday auction.

Trading Procedure	Auction-based
Trading Days	Year-round
Delivery Unit	15 minutes
Delivery period, admissible orders	**Quarter hourly (15min)** IDA 1: D [00:00-24:00] IDA2 D [00:00-24:00] IDA 3: D [12:00-24:00] Four 15min contracts open per corresponding underlying hour e.g. for HOUR 01, the following 15 min contracts will open: 00:00 – 00:15 00:15 – 00:30 00:30 – 00:45 00:45 – 01:00
Gate opening time	45 days before the Delivery Day
Gate Closure time	15:00 on day D-1 (IDA 1), 22:00 on day D (IDA2)10:00 on day D (IDA 3)
Publication time of preliminary results	GCT + ~17.5 min at the latest
Publication time of final results	GCT + ~20 min at the latest
Lot size (quantity characteristic during Order submission, minimum quantity)	0.1 MW
Price characteristics	in Euro/MWh with one decimal digits
Minimum and Maximum prices	-9999 EUR/MWh / 9999 EUR/MWh
Tick size (price characteristic during Order submission)	0.1 EUR/MWh
Results	Rounded market clearing price with two decimal digits
Exceptional procedure	In case of impossibility to perform HUPX Intraday Auction Market, the relevant Trading Session shall be cancelled and HUPX Intraday Continuous Market shall be the only trading platform for intraday Market Coupling [49].
Negative Prices	Negative prices are authorized where specified below (see minimum and maximum prices). NB: When a contract is traded with a negative price, it is legally regarded as a supply of service (removal service) by the recipient of power to the delivering party and not anymore as a supply of goods by the party delivering the power
Order types	a) Linear Order; b) Block Order
Constraints	Maximum quantity for Linear Order: 100,000 MW Maximum quantity for Block Order: 400 MW

Linear Orders	
Minimum and Maximum numbers of price/quantity combinations for Single Contracts orders	2 and 256
Block Orders	
Definition	Order on one or several combined Contracts with a minimum of one Contract of the same Delivery Day. Expiries depend on each other in their execution.
Specific conditions	All-or None The maximum number of Block Orders: 40
Smart blocks – linked	A Linked block group is a set of Block Orders which have together a linked execution constraint. Maximum values of linked block groups: Number of generations: 7 Number of children for a parent block: 6 Number of parents for a child block: 1 Size of a linked block group: 7 Number of linked block groups per portfolio: 5
Smart Blocks – linked (loop)	Loop blocks are defined as a set of 2 classic profile Blocks (1 sell and 1 buy Block for instance) that are either both accepted, or both rejected. Maximum values of linked loop block groups: Number of Block Orders in a linked loop Block group: 2 Number of linked loop Block groups per portfolio: 3 Maximum aggregated net volume of a linked loop Block group: 400 MW
Smart blocks - exclusive	An Exclusive block group is a set of Block Orders within which a maximum of one Block Order can be executed. (Best conditions) Maximum values of exclusive block groups: Number of blocks in an exclusive block group: 24 Number of exclusive block groups per portfolio: 10

The exceptional procedure referring to continued trading through the intraday continuous market is consistent with the applicable HUPX market description [49].

3.2.6.3 Input Data of Market Operators

3.2.6.3.1 Bid and Ask Curves

Bid and ask curves aggregate all submitted orders for a given market area, delivery date and time step, with separate purchase and sale curves.

The intersection of the purchase and sale curves determines the Market Clearing Price [50].

Each curve comprises a set of price–quantity points.

The aggregated-curve input is an XML file containing the supply and demand curves, net position and executed block orders for the relevant delivery day.

Block data

Block files contain the parameters of block bids for the relevant day. Negative quantities represent sell offers, while positive quantities represent buy offers.

For the neighbouring bidding zones included in the demonstration, international energy-market inputs were prepared for Austria, Slovakia and Czechia using publicly available data from the corresponding NEMOs: EPEX SPOT, OKTE and OTE. As these NEMOs did not participate directly in the demonstration data exchange, their market inputs were processed by the Artelys bid-generation framework from the available published market data. The resulting zonal supply and demand representations were harmonised with the Hungarian energy-order data and converted into the common internal order-book structure required by the market-clearing model. This approach enabled AT, SK and CZ to be represented consistently in the coupled calculation while accounting for the different source formats and levels of aggregation available from the respective market operators.

3.3 Balancing Capacity Market Design and Data Flows

This section describes the balancing-capacity market framework and input datasets used in the Hungarian demonstration. It presents the relevant Hungarian procurement processes, balancing products, tender timeframes and market-participation conditions, together with the structure and preprocessing of the anonymised balancing-capacity demand and supply data provided by MAVIR. These inputs constitute the balancing-capacity component of the co-optimised clearing problem and enable the demonstration to evaluate the coordinated procurement of energy and upward and downward balancing-capacity products across the day-ahead and intraday timeframes.

The Hungarian balancing capacity market operated by MAVIR has been established to tender and procure reserves for the purpose of electricity system balancing in advance of real-time. Nowadays, MAVIR procures reserves (FCR and FRR) on long-term (monthly-ahead) and short-term (day-ahead and intraday) tenders. To participate in the balancing capacity market, the partner is obliged to make an accreditation agreement and later must take an accreditation test successfully for the desired reserve type. The participation, more precisely the bidding, on the balancing capacity market tenders is not obligatory, unlike balancing energy market.

Month-ahead tenders are carried out in M-1 on weekdays, based on the tender calls published on MAVIR’s website. The capacity types procured and their specifications are listed in Table 13. The participation of non-conventional units (e.g. PV plants) is not allowed on month-ahead tenders.

Table 13. Month-ahead tenders and their specifications.

<table>
<tr><th>Capacity type</th><th>Product type</th><th>Specifications</th></tr>
<tr><td>aFRR negative</td><td rowspan="2">base load (BL),
weekdays/weekend</td><td rowspan="5">1-10 rounds (depending on market competition),
price reduction in each round</td></tr>
<tr><td>aFRR positive</td></tr>
<tr><td>aFRR negative</td><td rowspan="2">peak load (PL),
weekdays/weekend</td></tr>
<tr><td>aFRR positive</td></tr>
<tr><td>FCR</td><td>base load (BL), daily</td></tr>
</table>

Day-ahead tenders are held every day for four capacity types within pre-defined time periods as can be seen in Table 14. The day-ahead tenders are technology-independent, therefore renewable energy sources, including weather-dependent producers are also allowed to bid, except those producers that receive feed-in-tariffs (i.e. are within the so-called KÁT system).

Table 14. Day-ahead tenders and their specifications.

Capacity type	Product type	Gate opening time	Gate closure time
mFRR 12.5 positive	base load (BL)	D-2 12:00 p.m.	D-1 5:10 a.m.
FRR negative	hourly (H01-H24) each hour	D-1 8:00 a.m.	D-1 9:10 a.m.
FRR positive	hourly (H01-H24) each hour	D-1 8:00 a.m.	D-1 10:10 a.m.
FCR	base load (BL)	D-2 12:00 p.m.	D-1 10:50 a.m.

Intraday tenders are held in case the reserve needs cannot be fulfilled on the month-ahead and day-ahead procurements. Each unit with valid accreditation is invited to intraday tenders, except the ones receiving feed-in-tariff.

Table 15. Intraday tenders and their specifications.

Capacity type	Product type	Gate opening time	Gate closure time
FRR negative	hourly (H01-H24) one hour if called out	D-1 7:00 p.m.	T-140 (minutes)
FRR positive	hourly (H01-H24) one hour if called out	D-1 7:00 p.m.	T-120 (minutes)

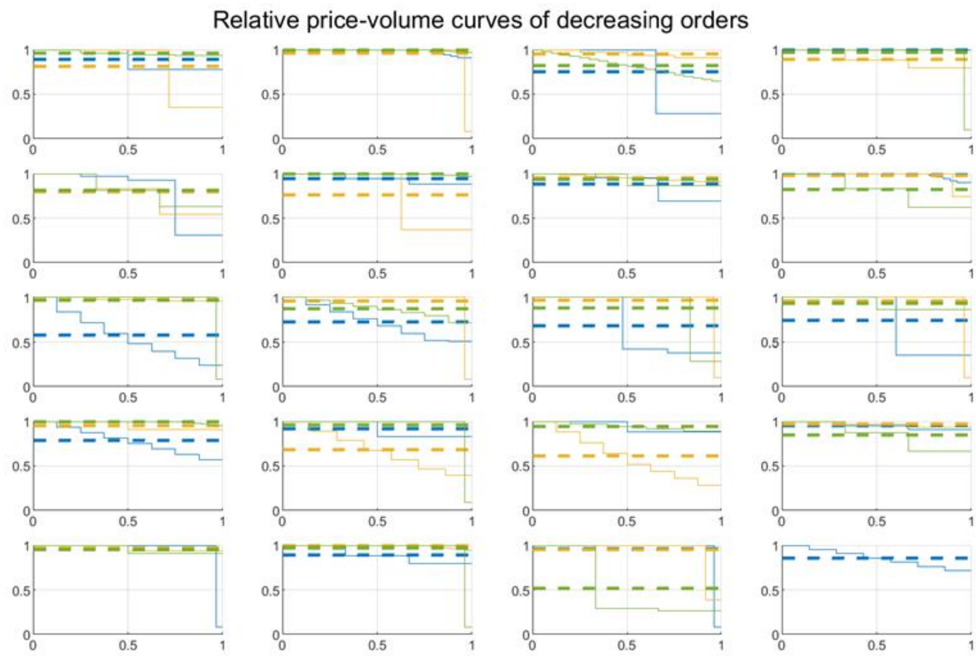


Figure 42. Relative price-quantity curves with decreasing price offers and their linearised relative unit prices.

The anonymised balancing-capacity dataset provided by MAVIR contains observed capacity requirements and capacity bids. The original bids may form non-monotonic price–quantity curves, shown by the thin lines in Figures 42 and 43. To support tractable optimisation, these curves are converted into linearised unit-price representations, shown by the dashed lines. This transformation enables the clearing model to optimise unit-price offers rather than non-monotonic multi-point curves, while retaining the principal price–volume characteristics of the submitted bids. Partner and unit identifiers have been anonymised to protect commercially sensitive information.

Figure 43. Relative price-quantity curves with changing price offers and their linearised relative unit prices.

Balancing capacity bids and demands have been shared as a common dataset but divided into day-ahead and intraday time horizons (one file each). Both files provided by MAVIR are originally in .CSV file format, shared on MAVIR Fileshare. In the future, these datasets will be accessible via GET API on the HUPX Labs platform, as well. The datasets consist of the following data:

- Period: unique tender identifier, first four characters representing the year, followed by a letter referring to the time horizon of the tender (D: day-ahead, I: intraday), then by the number of the day (e.g. 2023D123: day-ahead tender on the 123rd day of 2023)
- Start: start date of the tender (in YYYY.MM.DD format)
- End: end date of the tender (in YYYY.MM.DD format); the end date is identical with the start date in day-ahead and intraday time horizons
- Product: capacity tender type (FRR positive/FRR negative)
- Product type: the type of product in demand with acronyms
    - BL (base load), LT (low tariff), HT (high tariff): until the end of Q4 in 2022
    - HT (high tariff), LT (low tariff): in Q1 in 2023
    - H01-H24 (hourly), BL (aFRR negative base load): in Q2 in 2023

  - H01-H24 (hourly): from the beginning of Q3 in 2023 until the end of Q4 in 2023
  - H01–H24 (hourly), BL (mFRR positive base load): from Q1 2024 onwards
- Capacity type: offered product (aFRR positive/negative, mFRR 12.5 positive/negative)
- Demand volume: the quantity of capacity demand (in MW/h)
- mFRR limit: the quantity of FRR capacity demand to be provided with mFRR (in MW/h); the demand to be provided by aFRR is the difference between the demand volume and the mFRR limit
- Partner: partner identifier (here starting with 'BIDDER', followed by a number)
- Unit: unit identifier (here starting with 'UNIT', followed by a number)
- Bid volume: capacity volume offered by the partner with the given unit (in MW/h)
- Bid price: unit price of the capacity type (in HUF/MW/h)

Balancing capacity can be offered with 1 MW power steps in the day-ahead and intraday time horizons. The minimum and maximum bid price depends on the capacity type as follows:

- aFRR positive: minimum price: 1 HUF/MW/h, maximum price: 80000 HUF/MW/h
- aFRR negative: minimum price: 1 HUF/MW/h, maximum price: 80000 HUF/MW/h
- mFRR 12.5 positive: minimum price: 1 HUF/MW/h, maximum price: 25000 HUF/MW/h
- mFRR 12.5 negative: minimum price: 1 HUF/MW/h, maximum price: 25000 HUF/MW/h

In the case of base load (BL), high tariff (HT) and low tariff (LT) tenders, the product of the volume and the bid price must be multiplied by 24, 16 and 8, respectively, to calculate the service fee. Example: BIDDER1 with UNIT1 wins the HT tender (indicated in column 'Product type') with a bid volume of 50 MW/h and a bid price of 10000 HUF/MW/h, then the service fee of the offer will be 16×50×10000 HUF/MW/h. To determine the service fee of each unit in case of hourly bids (marked with H01-H24 in column 'Product type'), the volume should be multiplied by only the bid price.

Disclaimer: For the avoidance of doubt, the data provided so far or to be provided in the future by MAVIR based on the Data Transfer Request, as a part of the TwinEU project, is supplied „as is" without any guarantees or warranties, either expressed or implied. While reasonable efforts have been made to ensure the accuracy and completeness of the data, MAVIR makes no representations regarding its reliability, quality, suitability, or applicability for the project or any specific purpose. MAVIR does not take responsibility for any unexpected outcomes and complications stemming from the usage of such Data.

International balancing-capacity inputs for Austria, Slovakia and Czechia were generated from publicly available data reported by APG, SEPS and ČEPS through the ENTSO-E Transparency Platform. For the non-participating TSOs, the Artelys bid-generation framework processed the available historical balancing information and represented balancing-capacity supply and demand through zonal bid curves. These curves were interpolated from the published accepted balancing bids and transformed into the common product, time and price-volume representation used by the co-optimised market-clearing model. The resulting datasets provide a consistent representation of international balancing-capacity availability while recognising that they are reconstructed from public information rather than complete confidential TSO order books [51].

3.4 Transmission Capacity Calculation with DLR Extension

This section presents the transmission-capacity calculation process that provides the network constraints for the market-coupling simulations. It first summarises the principal steps, inputs and outputs of the Core flow-based capacity-calculation methodology and then describes its implementation across the day-ahead and successive intraday timeframes. The section also explains how DLR information is incorporated into the calculation: real-time conductor temperature is estimated using an ANN and converted into a line rating through a deterministic thermal model, while forecast ratings are calculated using deterministic CIGRE and IEEE methods based on the available weather forecasts. The resulting ratings are translated into updated RAM values for the relevant CNECs and subsequently applied in the market-clearing constraints.

3.4.1 Methodology of day-ahead capacity calculation

Day-ahead flow-based market coupling (DA FBMC) for the Core region was launched on the 8th of June 2022 for the following business day (9th of June 2022). This cooperation has been implemented into the single day-ahead coupling (SDAC) in Europe. The aim of the FBMC is to maximize the social welfare gained via exchanges between bidding zones and through an efficient cross-border transmission capacity allocation. These lead to a higher integration of national electricity markets, thus the harmonization of the electricity prices across the region. The range of possible cross-border capacity exchanges is determined by a so-called flow-based domain. The market clearing process utilizes the flow-based domain as one of the constraints to define a market clearing point where supply meets demand (market equilibrium). The day-ahead capacity calculation (DA CC) process begins in the afternoon in D-2 and lasts until D-1 10:00 a.m. with the determination of the flow-based domain for market coupling and subsequent post-coupling processes [52].

Figure 44. The Core DA FB CC process with its sub-steps.

The Core DA FB capacity calculation process requires correct inputs for precise results, which are mainly provided by Transmission System Operators (TSOs), Regional Coordination Centres (RCCs) and the Joint Allocation Office (JAO). After the delivery of the inputs, all the data are merged to create the starting point for the region. The main inputs of the capacity calculation process are:

- D-2 Congestion Forecast (D2CF Individual Grid Model) provided by the Core TSOs.
- Generation and Load Shift Keys (GLSKs): this allows the translation of a change in a bidding zone net position into a specific change of a generating unit or load.
- Critical Network Element Contingencies (CNECs) and Non-costly Remedial Actions (NRAs) in the zone of each TSO. This list contains the Critical Network Elements (CNEs) with associated N-1 contingencies (CNECs) per TSO.

- External Constraints (ECs) and Allocation Constraints (ACs): constraints that impose limits on Core or SDAC net positions respectively for a specific bidding zone.
- Long Term Nominations (LTNs) provided by TSOs for bidding zone borders with Physical Transmission Rights (PTRs) in the long-term timeframe. The only bidding zone border currently issuing PTRs is Croatian-Slovenian (HR-SI) border.
- Long-Term Allocations (LTAs) provided by JAO which are the result of the long-term capacity allocations in the yearly and monthly auctions.

The data merging entity (Coreso) and the Core Capacity Calculation tool (CCCt) first perform data quality checks (DQCs), primarily syntax and coherence checks, on the individual inputs before the capacity calculation process begins. In case an error is identified, TSOs can adapt and resend their datasets. During the merging step, the Individual Grid Models (IGMs) are merged by Coreso to create a Common Grid Model (CGM), which is considered the best prediction of the electricity grid. To achieve a balanced CGM, Coreso provides a common Core Net Position Forecast (NPF) during the merging process. If the IGMs' net position shows significant deviations from this Core NPF, the IGMs' net position is shifted towards the Core NPF. Also, in case of errors in the merging process, each individual input can be revised [52].

The CCCt determines the initial flow-based parameters based on the merged input files. These initial parameters consist of the sensitivity of the network elements on net position (NP) changes, initial power transfer distribution factors (PTDFinit) and remaining available margins (RAMs) for each CNEC. Afterwards, the CNEC selection is performed for each timestamp of the business day and CNEC. All the CNECs with a maximum zone-to-zone PTDFinit of smaller than 5% for any exchange within the Core region are removed. Therefore, the purpose of the CNEC selection is to point out those critical network elements that are not sensitive to cross-border exchanges and to remove those elements from the CNEC list which would limit the flow-based domain [52].

Non-costly remedial actions (NRAs) are used to enlarge the flow-based domain in the Non-costly Remedial Action Optimization (NRAO) process. The NRAO process aims to maximize the smallest relative RAM. The NRAO continues until the relative RAM cannot be increased on any CNEC any further. The Core DA FB CC involves two different NRAO optimization tools based on different algorithms but the same objective. The CCCt compares the outcomes of both NRAOs in each timestamp and selects the best results during the RAO selection. The resulting set of preventive remedial actions is applied to the CGM for later flow-based computation [52].

The Core CC tool computes the intermediate flow-based parameters including the selected remedial actions after the RAO selection. Furthermore, the intermediate computation extends the RAM by the adjustment for minimum RAM (RAM>AMR). The RAM>AMR is the translation of the requirement of 20% of Fmax (maximum physical load) for Core exchanges as well as the 70% of Fmax for cross-zonal (CZ) exchanges (both Core and non-Core) for each CNEC. Given the enlargement of CZ capacities, the RAM per CNEC is computed [52].

After the intermediate DA FB CC, the results are validated altogether and individually. The Core TSOs first provide a list of their remedial action potential for other TSOs, that should be later considered in their individual validation. The remedial action potential consists of both costly remedial actions (redispatch and countertrading) as well as non-costly remedial actions (topological measures and tap positions of phase shifting transformers/auto transformers). The DA FB CC process is further enhanced with a fully coordinated validation when implemented. During individual validation, each Core TSO (or consortium) validates CZ capacities to ensure operational security. If operational security is deemed to be at risk, TSOs may apply individual validation adjustments (IVAs). IVAs can be applied on CNECs and lead to a reduction of the RAM on the given CNEC. It should be noted that an increase of the RAM (inter alia a negative IVA) is not allowed in the Core DA FB CC process [52].

The pre-final computation is performed after the coordinated and/or individual validation. If CVAs and/or IVAs were applied, the RAM is reduced according to the adjustments. If a CVA or an IVA would lead to a negative RAM, the RAM is limited to 0 MW. If no CVA or IVA were applied, the pre-final domain will be identical with the intermediate domain. The domain computed in this step is published on the JAO Publication Tool (JAO PuTo).

The final flow-based computation process requires the latest status of all long-term capacity allocations (LTAs) and all long-term nominations (LTNs). The LTAs are based on long-term (yearly and monthly) auctions received from JAO, which reflect curtailments if applied by TSOs. The LTNs are received for each bidding zone border where physical transmission rights (PTRs) are issued. During the final computation, all LTNs are considered, and the LTAs and flow-based domain are shifted from zero balance to LTNs.

The final domain and LTAs, both shifted to LTNs, are published on the JAO PuTo, and provided to SDAC with all the allocation constraints. The SDAC market clearing process applies the Core flow-based domain combined with the LTAs to create constraints that limit the market clearing point (market equilibrium). Market clearing point can be also limited by the allocation constraints used by some Core TSOs.

In this project, MAVIR provides information on the net positions for each border of the Core capacity calculation region. The dataset provided by MAVIR contains the following data:

- id: hour identifier (from the launch of the flow-based capacity calculation)
- dateTimeUtc: period in UTC time zone (in YYYY-MM-DD hh:mm:ss format)
- border_XY_ZT: exchange at the border XY and ZT (in MW; from XY to ZT)

Other network capacity data is publicly available on the JAO (Joint Allocation Office) platform. Each data shared on the JAO platform can be acquired in CSV and XML format as well as through API connection. More information than what is available on the platform cannot be distributed without the permission of other TSOs in the Core CCR due to the Single DA and ID Coupling Observership and Non-Disclosure Agreement (often referred to as Global NDA).

3.4.2 Multi-timeframe capacity calculation and DLR integration

Within the TwinEU project, the conventional flow-based capacity calculation (CC) procedures are extended to support improved operational coordination across timeframes and market products. In this context, four capacity calculation runs are foreseen to be executed before each respective market gate closure: one Day-Ahead Capacity Calculation (DACC) preceding the single day-ahead coupling (SDAC), and three Intraday Capacity Calculations (IDCC1, IDCC2, IDCC3) preceding the respective intraday auctions (IDA1, IDA2, and IDA3). This temporal segmentation ensures that capacity values reflect the latest available grid information, with increasing accuracy and granularity as the physical delivery approaches.

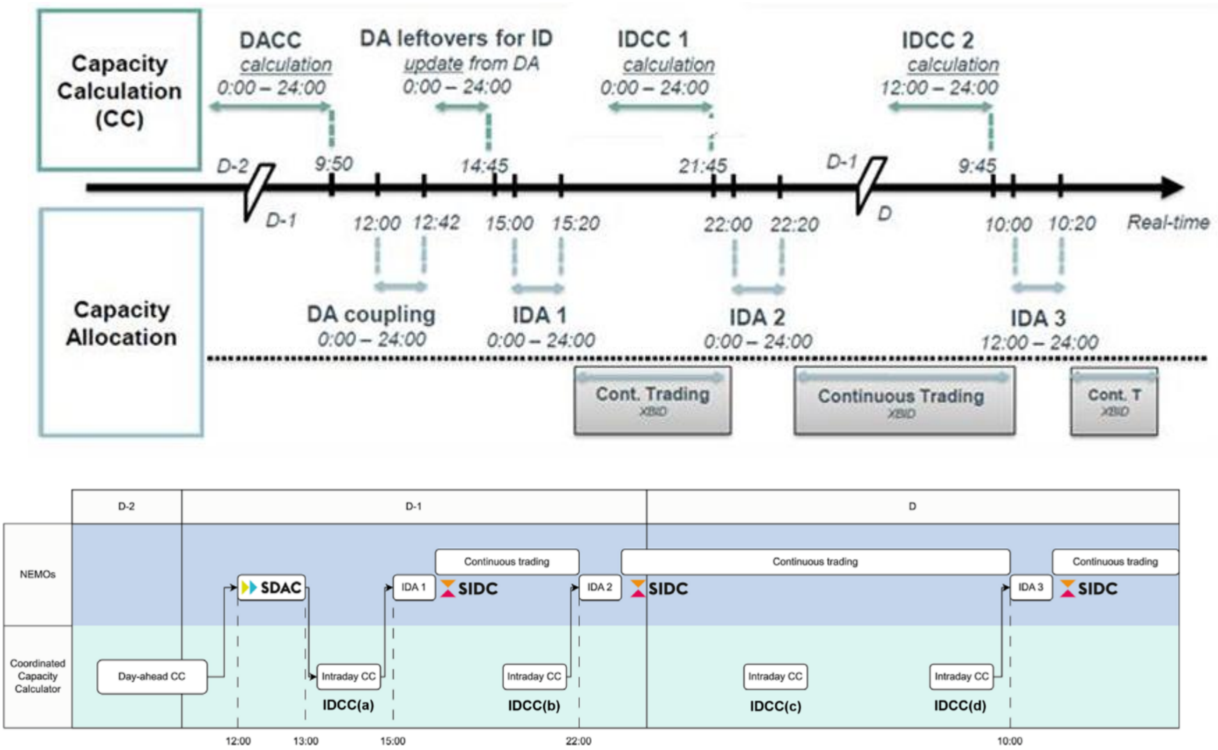


Figure 45. Timing of capacity calculation and market couplings [53].

The DACC is executed by 9:45 a.m. on D-1, followed by IDCC1 at 14:45 (D-1), IDCC2 at 21:45 (D-1), and IDCC3 at 09:45 (D), with IDCC1 and IDCC 2 covering capacity provision for the 0:00-24:00, and IDCC3 for the 12:00-24:00 interval of the delivery day. Each of these CC runs utilizes updated input datasets, such as revised net positions, updated remedial actions, and refreshed Common Grid Models (CGMs) to recalculate the flow-based domain. The objective of this multi-step CC approach is to ensure that the available cross-zonal capacities align as closely as possible with the real-time grid state, thereby increasing the efficiency and security of market coupling outcomes.

To further enhance the technical relevance and accuracy of the calculated capacities, the TwinEU project integrates Dynamic Line Rating (DLR) into the CC process on selected power lines. Traditional CC methodologies assume conservative static thermal ratings for transmission lines, typically derived from worst-case assumptions and fixed ambient conditions. This approach inherently underutilizes available grid resources under moderate or favourable environmental conditions. DLR offers a paradigm shift by enabling real-time adjustment of line ratings based on prevailing meteorological conditions and actual thermal state of the conductors, thereby unlocking latent transmission capacity and reducing the need for costly remedial actions or redispatch.

In the TwinEU framework, real-time DLR is determined through a two-stage process. First, an artificial neural network (ANN), trained on historical high-resolution sensor, weather and loading data, estimates the conductor temperature from the measured environmental and operational conditions. The ANN captures the complex nonlinear relationship between these inputs and the thermal behaviour of the overhead conductor. Second, the estimated conductor temperature is used in a deterministic thermal-rating calculation, which derives the admissible line loading based on the temperature estimate and the relevant physical and electrical parameters of the conductor. Accordingly, the ANN does not directly calculate the DLR value; it provides the conductor-temperature estimate required by the subsequent deterministic calculation.

For forecast applications in the TwinEU demonstration, DLR values are calculated using deterministic CIGRE and IEEE thermal-rating models rather than the ANN-based approach. These models use forecast meteorological parameters to determine the admissible loading of the relevant transmission lines. The resulting weather-dependent line ratings are mapped to the applicable Critical Network Elements with Contingency (CNECs) and used to update their Remaining Available Margin (RAM) values during the capacity-calculation process. Depending on the forecast conditions, the updated ratings may increase or decrease the available margin relative to the corresponding static line rating. The resulting RAM values are incorporated into the flow-based constraints used by the market-clearing calculation [37], [38].

The forecast-based application of DLR is subject to the availability of the required input data. In the implemented TwinEU workflow, suitable meteorological forecasts were available only for the following 24 hours. Furthermore, no corresponding load forecast was available to support the use of the ANN-based conductor-temperature model in forecasting mode. The ANN-based approach was therefore applied to measurement-supported real-time estimation, while forecast DLR values were calculated using the deterministic CIGRE and IEEE models. Consequently, DLR-enhanced RAM values could only be produced for market intervals falling within the available 24-hour weather-forecast horizon of each capacity-calculation run.

This limitation has direct implications on the scope of DLR integration in each CC run. For the DACC executed on D-1 at 9:45, DLR can be applied for market intervals up to D at 9:45. For IDCC1 (executed on D-1 at 14:45), DLR coverage extends until D at 14:45. Similarly, for IDCC2 (executed at 21:45), DLR remains valid until D at 21:45. The final IDCC3 run, executed on the delivery day (D) at 9:45, supports DLR application until the end of the trading period at 24:00. Importantly, since IDCC3 only determines capacities for the 12:00-24:00 window, DLR-enhanced values can fully span the relevant time horizon for this run. However, for earlier CCs, particularly the DACC, there will be hours within the 24-hour trading window for which DLR cannot be applied, and fallback to static ratings or probabilistic margins may be required.

To manage these complexities, the TwinEU project introduces scenario-based DLR integration. In the next section, a range of DLR scenarios are demonstrated.

The anticipated benefits of DLR integration are multifaceted. By enabling more dynamic and responsive capacity calculation, DLR contributes to

- increased cross-zonal exchange potential,
- reduced curtailment of renewables,
- enhanced market liquidity, and
- deferred grid reinforcement investments.

Moreover, DLR supports the broader policy goals of the European Green Deal and Fit-for-55 package by allowing higher penetrations of variable renewable energy sources (RES) without compromising system reliability.

3.5 Scenario Design, Workflow, and Execution

This section defines the complete scenario portfolio developed for the Hungarian Task 7.3 demonstration. Sections 3.5.1–3.5.3 describe the capacity-calculation, standalone market and sequential market configurations, including variants that were defined but not executed in the evaluated simulation batch. Section 3.5.4 presents the corresponding scenario identifiers and execution status. To avoid repetition, the exact target–baseline comparison pairs, KPI evaluation rules and quantitative outcomes are presented only in Section 3.7.

3.5.1 DLR Scenarios

3.5.1.1 Base Case

This scenario focuses on executing a comprehensive capacity calculation (CC) using the Artelys software platform, with the objective of establishing a robust base case for the Hungarian power system. The calculation is based on the integration of all available and relevant data sources, specifically the Ten-Year Network Development Plan (TYNDP), Joint Allocation Office (JAO) publications, and the MAVIR F110 input dataset. The scenario is designed to reflect the most accurate and representative state of the power system by combining forward-looking network data (TYNDP), cross-border capacity and allocation information (JAO), and detailed cross-border exchange data (MAVIR F110). The goal of this scenario is to enable a direct comparison between the recalculated base case capacity and actual operational outcomes, with a particular focus on capacity-related parameters. By recalculating the full system capacity using these data sources, the scenario provides a benchmark for evaluating the accuracy, completeness, and reliability of the base case model. This approach supports the identification of any discrepancies between planned, published, and real-time operational data, and helps to inform future improvements in capacity calculation methodologies and data integration practices. The scenario ultimately serves as a reference point for validating the capacity calculation process and ensuring that it meets both regulatory and operational requirements.

3.5.1.2 DLR light

This scenario investigates the impact of Dynamic Line Rating (DLR) on the Remaining Available Margin (RAM) of transmission lines identified as critical within the scope of Task 6.8. Starting from the base case RAM values, the scenario applies to a set of simplified modification logics to simulate potential DLR effects. The core methodology involves adjusting the RAM of each line by a factor (1.0 + RAM modification option), reflecting both possible increases and decreases in line capacity due to DLR implementation.

Several modification options are defined to capture a range of plausible DLR outcomes:

- **RAM110 and RAM120**: These options simulate a 10% and 20% increase in RAM, respectively, representing optimistic DLR scenarios where enhanced real-time thermal ratings allow for higher transfer capacities.
- **RAM95**: This option assumes a 5% decrease in RAM, acknowledging the possibility that DLR application may, under some conditions (such as conservative operational settings or adverse weather), reduce available capacity.
- **AltRAM100**: This option models a mixed scenario where DLR can both increase and decrease RAM on different lines, based on a preliminary analysis of Task 6.8 results. The specific lines and the direction/magnitude of changes are to be detailed according to the findings from Task 6.8, ensuring that the simulation reflects realistic, data-driven DLR impacts.

The scenario is designed to be evaluated over the full timescale of the TwinEU project, encompassing both historical and ongoing simulation runs. This temporal breadth allows for the assessment of DLR effects under a variety of system conditions and operational periods.

The primary goal of this scenario is to evaluate how DLR-induced changes in RAM (positive or negative) affect the operational performance, reliability, and congestion patterns of the transmission grid. By systematically applying these RAM modification options, the scenario provides insights into the sensitivity of critical network elements to DLR, identifies lines where DLR could introduce operational challenges or improvements, and supports the validation and refinement of DLR integration strategies for future capacity calculations.

3.5.1.3 DLR

This scenario focuses on simulating the effects of DLR on the RAM of critical transmission lines identified in Task 6.8, using historical data from a specified time period. The simulation applies simplified RAM adjustments to these lines using the formula 1.0 + modified RAM value, where the modification factors are derived from DLR results. The analysis is restricted to the historical timeframe covered by Task 6.8, as continuous DLR input data is unavailable for the entire TwinEU project duration.

The scenario leverages historical operational datasets from two transmission system operators (TSOs) and one 120 kV distribution system operator (DSO): MAVIR (Hungary TSO), EON (Hungary DSO), and APG (Austria). These datasets can be analyzed either separately (to assess TSO-specific impacts) or combined (to evaluate cross-border or system-wide effects). The RAM modifications are applied exclusively to lines explicitly defined in Task 6.8, ensuring a targeted assessment of DLR's impact on pre-identified critical infrastructure. The limited DLR data availability necessitates a retrospective analysis rather than real-time or future projections. This approach ensures consistency with the empirical results from Task 6.8, which provides a validated foundation for the RAM adjustment factors.

The goal is to quantify how DLR-driven RAM changes affect the operational performance and reliability of critical lines during the historical period. Key objectives include:

1. Determining whether DLR implementation would have increased, decreased, or variably altered RAM under past grid conditions.
2. Identifying patterns in DLR's impact across different TSO and DSO regions (MAVIR, EON, APG) or in combined system operations.
3. Validating the simplified RAM modification logic against Task 6.8 findings to refine future DLR modeling assumptions.

Focusing on historical data, this scenario provides actionable insights into DLR's potential benefits and risks while circumventing uncertainties associated with forward-looking simulations.

In the scenario matrix, the numerical character of each scenario identifier denotes the applied capacity-calculation variant: 0 represents the reference configuration without DLR, 1 represents the DLR-light configuration and 2 represents the DLR-enhanced configuration. In the simulation batch evaluated in Section 3.7, the reference and DLR-enhanced variants were executed for the selected DAM and IDA2 configurations. The DLR-light configurations remain part of the complete scenario design but were not executed in this batch.

3.5.2 Co-Optimisation Market Data Scenarios

3.5.2.1 Base case

This scenario represents the reference market model, characterized by the separation of the Energy Market and the Balancing Capacity (BC) Market. The simulation is executed without co-optimisation, meaning that BC is procured independently from the energy market clearing. It serves as the foundational benchmark for analysing market outcomes in a non-co-optimised setting, using the standard TwinEU dataset. The purpose of this scenario is to enable a direct comparison between model results and actual market outcomes, particularly in terms of market performance and structure. The analysis focuses on evaluating how well the simplified and modular approach of the TwinEU modelling framework reflects real-world dynamics, including the limitations and assumptions inherent to a decoupled market-clearing mechanism. This base case scenario is essential for establishing a reference point against which all co-optimisation variations are compared.

The final scenario matrix distinguishes the standalone non-co-optimised reference by market stage. Scenario A0 denotes the SLR-based DAM reference, while B0 denotes the corresponding SLR-based IDA2 reference. Their DLR-light and DLR-enhanced equivalents remain defined in the matrix as A1/A2 and B1/B2, respectively, although they were not executed in the evaluated batch.

3.5.2.2 Co-Optimisation Basic: Day-Ahead Market (DAM)

This scenario explores the effects of implementing co-optimisation between the DAM energy and BC markets, using detailed market data provided by TwinEU Hungarian pilot partners, specifically MAVIR and HUPX, and publicly available or external source datasets from neighboring zones such as Austria (AT), Slovakia (SK) and Czech Republic (CZ). The model integrates both markets into a unified clearing process, allowing simultaneous optimization of energy dispatch and BC procurement based on a common objective of maximizing social welfare while ensuring reliability. The scenario is designed to assess the economic and operational implications of such market integration, evaluating key indicators including social welfare, energy and BC prices, total BC procurement costs, and supply adequacy. By comparing the results with those of the separated market base case, this scenario highlights the potential benefits and trade-offs of introducing co-optimisation at the DAM stage, offering insights into how coordinated market mechanisms could enhance efficiency and flexibility in power system operations.

In the final scenario convention, the basic standalone DAM co-optimisation configuration is represented by the C-family with sub-scenario a. C0a denotes the SLR-based configuration, C1a the DLR-light configuration and C2a the DLR-enhanced configuration. C0a and C2a were executed in the evaluated simulation batch.

3.5.2.3 Co-Optimisation Basic: Intraday Market (IDM)

This scenario extends the co-optimisation approach to the IDM, applying the same data sources and modeling principles as the DAM co-optimisation case (3.5.2.2), but adapted to the closer-to-real-time timeframe of intraday auctions (e.g., IDA1, IDA2, IDA3). It uses detailed input data from MAVIR and HUPX, along with publicly available market data from AT, SK and CZ, to simulate a co-optimised clearing of energy and BC within the intraday market framework. The aim is to evaluate how co-optimisation performs under more dynamic conditions, where updated forecasts and shifting market conditions play a larger role. The analysis focuses on social welfare changes, intraday price evolution, BC procurement efficiency, and overall supply reliability. When compared to both the base case

(3.5.2.1) and the DAM co-optimisation scenario (3.5.2.2), this scenario offers insights into the incremental value of intraday co-optimisation and its potential to support enhanced system responsiveness and flexibility.

The scenario matrix assigns separate identifier families to the individual intraday auctions: E for IDA1, D for IDA2 and F for IDA3. The basic co-optimisation variant is denoted by the suffix a. The quantitative evaluation focuses on D0a and D2a because IDA2 was the complete intraday auction selected for the principal comparison, while the corresponding IDA1 and IDA3 configurations were not executed in the evaluated batch.

3.5.2.4 BC Variation – Alternative Hungarian Supply Data: DAM

In this scenario, the DAM co-optimisation framework is retained, but the Hungarian BC supply bid data is replaced with an alternative dataset sourced from the ENTSO-E Transparency Platform, instead of using the MAVIR-provided bids originally modified for the TwinEU project. While the energy market input remains unchanged from the standard DAM co-optimisation case (3.5.2.2), the alternative BC dataset is used to mitigate the influence of extensive post-processing that was applied to MAVIR's original bids, including linearization and price modification. This setup allows for a more conservative and representative simulation of Hungarian reserve supply offers. The scenario aims to assess the impact of these input changes on co-optimisation outcomes by comparing social welfare, wholesale electricity prices, BC prices, procurement costs, and supply availability with both the base case (3.5.2.1) and the standard DAM co-optimisation scenario (3.5.2.2). It provides a sensitivity analysis that highlights the role of bid data fidelity and supports the validation of results using publicly available, minimally altered market data.

This DAM input-data variation is represented by the C-family with suffix b. C0b was executed using the reference SLR-based capacity domain, while C1b and C2b remain defined but unexecuted configurations.

3.5.2.5 BC Variation – Alternative Hungarian Supply Data: IDM

This scenario mirrors the approach of the previous DAM variation but is applied within the IDM co-optimisation framework. It substitutes MAVIR's modified BC bid data with raw data from the ENTSO-E Transparency Platform, while keeping the energy market input identical to the original Intraday co-optimisation scenario. As in the DAM variant, the intention is to evaluate how reduced data manipulation and closer alignment with public sources influence market outcomes in a co-optimised IDM setting. This approach ensures a more transparent and potentially more reliable assessment of BC market behavior. The analysis compares the results against both the base case (3.5.2.1) and the standard IDM co-optimisation scenario (3.5.2.3), examining indicators such as social welfare, intraday and BC prices, procurement costs, and overall market performance. Through this comparison, the scenario contributes to understanding the sensitivity of co-optimisation models to data preprocessing and highlights alternative modeling paths that ensure consistency with publicly accessible datasets.

The same b suffix is used for the intraday bid-source variations. The executed IDA2 configuration is D0b. The corresponding IDA1, IDA3, DLR-light and DLR-enhanced variants remain part of the matrix but were not included in the evaluated simulation batch.

3.5.2.6 Bid Forwarding in IDM

This scenario introduces bid forwarding into the IDM co-optimisation framework, enhancing the model by incorporating temporal bid interlinkages across successive intraday auctions (e.g., IDA1, IDA2, IDA3). The simulation uses the same input data as either the basic IDM co-optimisation scenario (3.5.2.3) or its variation with alternative Hungarian supply bids (3.5.2.5) but adds a bid forwarding mechanism that transfers unaccepted bids from earlier intraday auctions to subsequent ones within the same delivery day. While technically this constitutes a cascaded market structure between the DAM and IDM auctions, bid forwarding is only implemented among the IDM auction instances themselves. The goal is to simulate a more dynamic and realistic IDM, where market participants can remain active across multiple auction rounds. This setup aims to evaluate how this added market behavior impacts social welfare, intraday and BC prices, procurement costs, and supply efficiency. By comparing the results to those of the base case (3.5.2.1) and standard ID co-optimisation scenarios (3.5.2.3 and 3.5.2.5), the scenario offers insights into how bid forwarding enhances market flexibility and can lead to more efficient balancing outcomes.

The bid-forwarding configuration is represented by the H-family with suffix c. H0c denotes the complete SLR-based sequential workflow, while individual results are referred to by appending the relevant market stage, for example H0c/DAM, H0c/IDA1 or H0c/IDA2. The mechanism itself forwards residual bids between the intraday auction instances; the DAM result is retained as the initial consistency reference. The required IDA3 PTDF input was unavailable, and the IDA3 output of the sequence was therefore not evaluated.

3.5.2.7 Intraday-Intensive Markets: Combined DAM+IDM Co-Optimisation

This scenario explores the implications of shifting towards a more intraday-intensive market design, where a significant share (typically around 10-20%) of the total TSO BC demand is moved from DAM to the IDM timeframe. The simulation combines DAM and IDM (IDA1, IDA2, IDA3) co-optimisation in a single integrated run, using input data from any of the previous IDM scenarios (3.5.2.3, 3.5.2.5 or 3.5.2.6), while modifying the BC demand profiles and applying bid forwarding mechanisms to simulate active intraday participation. The DAM demand is deliberately reduced to reflect a strategic deferral of procurement, motivated by the availability of more accurate short-term data, such as improved weather forecasts or DLR information. Optionally, the energy market component of the model may also reflect a more active IDM structure, emulating real-world trading patterns. The purpose of the scenario is to assess how such a market configuration affects social welfare, pricing behavior in both energy and BC markets, total procurement costs, and supply adequacy. Compared to the base case (3.5.2.1) and earlier ID co-optimisation scenarios (3.5.2.3 through 3.5.2.6), this setup provides valuable insights into the benefits and challenges of a system that increasingly relies on the intraday timeframe for balancing, potentially enhancing operational efficiency and responsiveness.

This non-cascaded intraday-intensive configuration remained a conceptual scenario and was not instantiated as a separately executed configuration in the final evaluated matrix. Its cascaded extension is retained as the d variant described in Section 3.5.3.3. No quantitative results are reported for the intraday-intensive configuration in Section 3.7.

3.5.3 Cascaded Co-Optimisation Market Data Scenarios

3.5.3.1 Cascaded Basic Co-Optimisation (DAM+IDM)

This scenario applies a comprehensive cascading process to the DAM and IDM (IDA1, IDA2, IDA3) co-optimisation framework based on the input data from either the basic co-optimisation setup (3.5.2.1) using MAVIR/HUPX and public regional data or its variation with alternative Hungarian BC supply bids from the ENTSO-E Transparency Portal. In addition to the co-optimised market setup, a new capacity calculation step is introduced between each auction instance. This capacity calculation cycle uses the standard inputs described in scenarios (3.5.1) but adjusts the RAM according to the results of preceding market auctions. This allows the model to better simulate the interplay between market outcomes and network constraints. The scenario aims to analyze how this more detailed interaction between market and CC influences social welfare, price formation in the energy and balancing capacity markets, total procurement costs, and system efficiency. The results are compared against earlier basic co-optimisation scenarios to understand the added value of including realistic, sequential capacity updates in the co-optimisation process.

The RAM-cascading configuration without bid forwarding is represented by the G-family. The suffix a denotes the basic market-data configuration, while b denotes the alternative Hungarian balancing-capacity input variant. G0a was executed using the SLR-based domain. Its stage-specific outputs are referred to as G0a/DAM, G0a/IDA1, G0a/IDA2 and, where available, G0a/IDA3. The other G-family configurations remain defined but were not executed in the evaluated batch.

3.5.3.2 Cascaded Co-Optimisation with Bid Forwarding

This scenario builds upon the previously introduced bid forwarding mechanism (3.5.2.6), now embedding it into a full cascaded DAM and IDM co-optimisation process. Using the same input data from the bid forwarding case the scenario includes a sequential recalculation of RAM after each auction. The recalculation follows the standard methodology defined in scenarios 3.5.1 but incorporates adjustments based on the outcome of each preceding market clearing. This enables a more accurate representation of how market activity influences transmission capacity availability for subsequent timeframes. The objective is to assess the cumulative effect of bid forwarding and realistic, time-linked capacity constraints on market efficiency, welfare, pricing behavior, and procurement outcomes. Results are benchmarked against the simpler bid forwarding scenario without cascading (3.5.2.6), highlighting the impact of tighter integration between market clearing and network capacity management.

The combined transfer of residual bids and residual RAM is represented by the I-family with suffix c. I0c denotes the executed SLR-based sequence. Its individual auction-stage outputs are referred to as I0c/DAM, I0c/IDA1, I0c/IDA2 and I0c/IDA3, subject to the availability of the required stage-specific inputs.

3.5.3.3 Cascaded Co-Optimisation for Intraday-Intensive Markets

This scenario extends the intraday-intensive market simulation (3.5.2.7) into a fully cascaded co-optimisation framework, combining DAM and IDM auctions (IDA1, IDA2, IDA3) with a sequential capacity recalculation between each auction stage. Based on the same market data and assumptions where 10-20% of TSO balancing capacity demand is shifted from DA to ID, and bid forwarding is applied, the scenario implements a new capacity calculation cycle using the standard parameters (as in scenarios 3.5.1), dynamically updated according to the results of each market stage. This setup is designed to reflect a highly dynamic operational environment, where both demand shifts and network constraints evolve throughout the trading day. The scenario provides insights into the combined effects of more active intraday procurement strategies, bid forwarding mechanisms, and real-time adjustments to cross-zonal capacity. It is compared to the non-cascaded version of the ID-intensive market scenario (3.5.2.7), enabling a deeper understanding of how cascading processes enhance realism and potentially improve the efficiency and responsiveness of co-optimised electricity markets.

The cascaded intraday-intensive configuration is represented by the I-family with suffix d. The configurations I0d, I1d and I2d remain defined in the scenario matrix but were not executed in the evaluated simulation batch. They are consequently not included in the quantitative comparisons in Section 3.7.

3.5.4 Scenario matrix

Table 16. Complete scenario matrix.

			Capacity Calculation		
			1.0	1.1	1.2
			w/o DLR	DLR Light	DLR
Market	2.0 w/o Co-optimization	DA	A0	A1	A2
		IDA2	B0	B1	B2
	2.1 Standalone co-optimization	DA a)	C0a	C1a	C2a
		DA b)	C0b	C1b	C2b
		ID: IDA1 a)	E0a	E1a	E2a
		ID: IDA1 b)	E0b	E1b	E2b
		ID: IDA2 a)	D0a	D1a	D2a
		ID: IDA2 b)	D0b	D1b	D2b
		ID: IDA3 a)	F0a	F1a	F2a
		ID: IDA3 b)	F0b	F1b	F2b
	3.0 Sequential and cascaded scenarios	RAM cascading + DA a)	G0a	G1a	G2a
		RAM cascading + DA b)	G0b	G1b	G2b
		ID: IDA c)	H0c	H1c	H2c
		RAM cascading + IDA c)	I0c	I1c	I2c
		RAM cascading + IDA d)	I0d	I1d	I2d

Green cells indicate executed configurations; grey cells indicate configurations defined but not executed in the evaluated simulation batch.

Scenario identifiers follow a systematic three-part convention. The first uppercase letter denotes the market configuration and generally follows the vertical order of the market scenarios in the matrix. The numerical character denotes the capacity calculation variant: 0 represents the reference SLR-based domain, 1 the simplified DLR-light domain and 2 the DLR-enhanced domain. A final lowercase letter is used where multiple market-data or operational sub-scenarios are defined within the same market configuration. For example, C0a denotes the basic standalone DAM co-optimisation case using SLR-based capacity, whereas C2a denotes the corresponding DLR-enhanced case.

The colour coding of the matrix distinguishes between executed and non-executed configurations. Green cells indicate scenarios for which results were available in the simulation batch evaluated in Section 3.7. Grey cells indicate configurations that remain part of the complete scenario architecture but were not executed in the current batch.

The executed standalone configurations were A0, B0, C0a, C0b, C2a, D0a, D0b and D2a. The executed sequential scenario families were G0a, H0c and I0c. For these sequential configurations, the identifier denotes the complete market sequence; where a specific auction result is referenced, the market stage is appended to the identifier, for example G0a/DAM, H0c/IDA2 or I0c/IDA2.

The IDA3 stage of the bid-forwarding sequence was unavailable because the required PTDF data were not provided. Other grey configurations, including all DLR-light and intraday-intensive variants, were defined but not executed in the evaluated batch.

The controlled target–baseline comparison pairs are defined in Section 3.7.4. Their KPI evaluation rules are given in Section 3.7.3, and the quantitative results are presented in Sections 3.7.4 and 3.7.5. These elements are not repeated here so that the present section remains focused on scenario definition and execution status.

3.6 Co-Optimised Market-Clearing Algorithm

3.6.1 General Presentation

In the context of use case HU03, a market clearing algorithm relying on the co-optimisation of energy and balancing bids in short-term markets will be developed and consolidated by Artelys, which is the main technology provider in Task 7.3 of TwinEU.

The workflow notably builds upon previous development efforts conducted by BME in the context of the FARCROSS project, which resulted in a previous deployment including a prototype for the co-optimised approach of auctioning the available transmission capacity to both energy and reserve allocation.

In this section, we present the main steps of the methodology to be implemented, with a focus on the generation and processing of cross-border bids, flow-based market coupling constraints, and the processing of these auctions under different market clearing scenarios (e.g. regarding the co-optimisation of balancing and energy bids).

The general workflow and its connection with input data sources is presented in the figure below. In the following paragraphs, we detail the three main steps of this workflow, i.e. bid generation, flow-based market coupling constraint processing and market clearing, and we provide an overview of the general results that could be made available through the HUPX LABS platform.

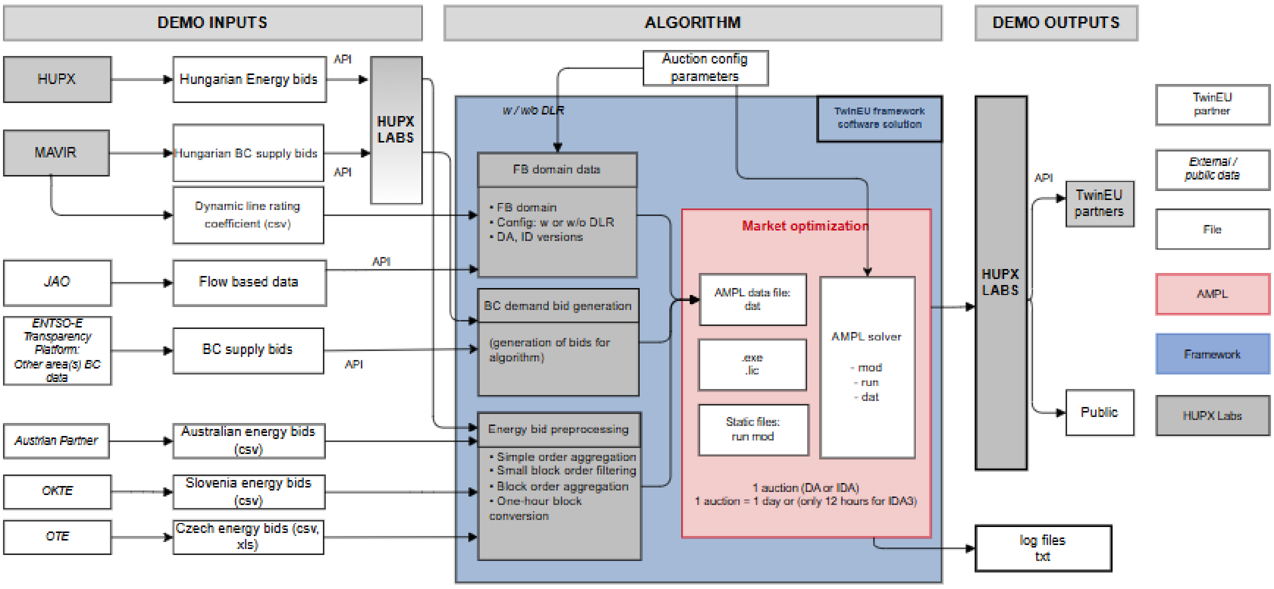


Figure 46. Workflow diagram for use case HU03 of the Hungarian demonstration.

3.6.2 Bid generation

In this exercise, internal bids from the Hungarian bidding zone are made available by HUPX and MAVIR and should not require advanced processing efforts. The developed model will be capable of integrating various bid formats, depending on whether they apply to single or multiple market intervals (simple v. block orders), the nature of the bid (energy supply, demand, upward & downward balancing), with a possibility to identify order groups that are exclusive (combined orders).

This leads to the following categories of products:

- Simple energy supply orders,
- Simple energy demand orders,
- Simple and exclusive block energy supply orders,
- Simple and exclusive block energy demand orders,
- Simple upward balancing supply orders,
- Simple upward balancing demand orders,
- Simple downward balancing supply orders,
- Simple downward balancing demand orders,

On the other hand, key developments are to be conducted to enable the processing of cross-border energy and balancing bids from third countries that are relevant to this demo.

3.6.2.1 Domestic balancing bids

Balancing capacity bids and demands are shared by MAVIR and divided into day-ahead and intraday time horizons, with datasets consisting in the following data:

- Period: unique tender identifier, first four characters representing the year, followed by a letter referring to the time horizon of the tender (D: day-ahead, I: intraday), then by the number of the day (e.g. 2023D123: day-ahead tender on the 123rd day of 2023)
- Start: start date of the tender (in YYYY.MM.DD format)
- End: end date of the tender (in YYYY.MM.DD format); the end date is identical with the start date in day-ahead and intraday time horizons
- Product: capacity tender type (FRR positive/FRR negative)
- Product type: the type of product in demand with acronyms
    - BL (base load), LT (low tariff), HT (high tariff): until the end of Q4 in 2022
    - HT (high tariff), LT (low tariff): in Q1 in 2023
    - H01-H24 (hourly), BL (aFRR negative base load): in Q2 in 2023
    - H01-H24 (hourly): from the beginning of Q3 in 2023 until the end of Q4 in 2023
    - H01–H24 (hourly), BL (mFRR positive base load): from Q1 2024 onwards
- Capacity type: offered product (aFRR positive/aFRR negative/mFRR 12.5 positive/ mFRR 12.5 negative)
- Demand volume: the quantity of capacity demand (in MW/h)
- mFRR limit: the quantity of FRR capacity demand to be provided with mFRR (in MW/h); the demand to be provided by aFRR is the difference between the demand volume and the mFRR limit
- Partner: partner identifier (here starting with 'BIDDER', followed by a number)
- Unit: unit identifier (here starting with 'UNIT', followed by a number)
- Bid volume: capacity volume offered by the partner with the given unit (in MW/h)
- Bid price: unit price of the capacity type (in HUF/MW/h)

Balancing capacity can be offered with 1 MW power steps in the day-ahead and intraday time horizons. The minimum and maximum bid price depends on the capacity type as follows.

- aFRR positive: minimum price: 1 HUF/MW/h, maximum price: 80000 HUF/MW/h
- aFRR negative: minimum price: 1 HUF/MW/h, maximum price: 80000 HUF/MW/h
- mFRR 12.5 positive: minimum price: 1 HUF/MW/h, maximum price: 25000 HUF/MW/h
- mFRR 12.5 negative: minimum price: 1 HUF/MW/h, maximum price: 25000 HUF/MW/h

3.6.2.2 Domestic energy bids

For the demonstration, HUPX also provided a weekly test dataset that is generated from an XML into XLS format. Hourly and block bidding data is represented in the provided data. The main general attributes are the following:

- *ID number*: HUPX balancing group, date and type of file, the format is similar to 'Orders-15X-HUPX------5-YYYYMMDD';
- *Delivery area*: e.g. '10YHU-MAVIR----U-20180325';

The hourly-specific part is listed below:

- *Hours: the bid interval for the given period (day);*
- *Quantity: the exact amount in MW;*
- *Price: the positive or negative bid value in EUR/MWh;*

- *Quantity of price intervals: in integer format.*

The block bidding attributes are handled within the same document but the rows are separated. The following information about block bids is stored in the data set:

- *Date of bid administration*;
- *Direction of the bid*: 'S' in case of sell, 'B' in case of buy;
- *MinimumAcceptanceRatio*;
- *Limit price*: the unit of measurement is EUR/MWh
- *Hours*: number of hours for the given period (day);
- *Volume*: in number format and in MWh.

3.6.2.3 Cross-border balancing bids

Cross-border balancing bids from Austria, Slovakia and Czechia will be generated based on data from ENTSO-E's Transparency Platform.

The ENTSO-E Transparency Platform is a comprehensive repository of data related to the European electricity market, featuring detailed information on electricity generation, load, cross-border flows, outages, balancing, and market forecasts. The platform provides real-time and historical data on power generation by fuel type, demand forecasts and historical load, outage events, cross-zonal capacity and flows, as well as detailed information on balancing services and market operations. All information is standardized according to Regulation (EU) No. 543/2013, which mandates consistent and timely reporting by transmission system operators (TSOs), market participants, and third-party providers. The data is accessible in multiple formats, including CSV downloads and extraction through RESTful API calls.

In the model, balancing capacity can be offered with 1 MW power steps in the day-ahead and intraday time horizons. The minimum and maximum bid price depends on the capacity type as follows.

- *aFRR positive: minimum price: 1 HUF/MW/h, maximum price: 80000 HUF/MW/h*
- *aFRR negative: minimum price: 1 HUF/MW/h, maximum price: 80000 HUF/MW/h*
- *mFRR 12.5 positive: minimum price: 1 HUF/MW/h, maximum price: 25000 HUF/MW/h*
- *mFRR 12.5 negative: minimum price: 1 HUF/MW/h, maximum price: 25000 HUF/MW/h*

In the current demo, balancing bids for supply and demand are represented through supply and demand curves that are interpolated based on accepted balancing bids in the ENTSO-E Transparency Platform.

3.6.2.4 Cross-border energy bids

Cross-border energy bids from Austria, Slovakia and Czechia are to be processed based on various data sources including Nominated Electricity Market Operators (NEMOs) for the corresponding country. As for balancing bids, the objective is to consolidate supply and demand curves as published by the market operators, which will then be used in the market clearing step.

3.6.3 Flow-based market coupling constraints

Flow-based market coupling constraints are integrated into the workflow directly from the Joint Allocation Office (JAO) publication tool for the Core Capacity Calculation Region [54].

The JAO Publication Tool serves as a central platform for accessing detailed data related to the Core Flow-Based Day-Ahead Market Coupling (Core FB DA MC) and Intraday Capacity Calculation (IDCC) processes. It provides comprehensive datasets including net positions, cross-zonal capacities (ATC/NTC), scheduled exchanges, congestion income, allocation constraints, and remedial actions since the go-live of Flow-Based market coupling in the Core region in June 2022. The tool offers both a web interface and RESTful API for data retrieval, supporting formats like CSV and JSON.

In the model, flow-based domains are included through the following parameters:

- *The number of considered Critical Network Elements and Contingencies (CNECs),*
- *The remaining available margin (RAM), relevant time periods and list of power transfer distribution factors (PTDFs) associated with each CNEC.*

In particular, an additional data processing step is activable to take into account dynamic line rating parameters provided by MAVIR, including:

3.6.3.1 Static data

- *Country/System operator*
- *Power line name*
- *Nominal voltage [kV]*
- *Number of circuits [-]*
- *Static Line Rating (summer) [A]*
- *Static Line Rating (winter) [A]*
- *Substation limit [A]*

3.6.3.2 Dynamic Data

- *Timestamp [YYYY.MM.DD.hh.mm.ss.]*
- *Voltage at substation 'A' [kV]*
- *Voltage at substation 'B' [kV]*
- *Power factor [-]*
- *Load from the SCADA system [A]*
- *Dynamic Line Rating (conductor) [A]*
- *Dynamic Line Rating (power line) [A]*

These parameters are then used to update RAMs for relevant CNECs in historical JAO flow-based data. In particular, one should note that the FB MC data published on the JAO platform include a presolve indicator that simplifies the pre-processing of redundant constraints.

In parallel, Artelys has developed a capacity calculation module based on the PowSyBl open-source Java framework, based on data from ENTSO-E's Ten-Year Network Development Plan (TYNDP), notably combining zonal supply-demand data from the "National Trends 2030" scenario in the TYNDP 2024 and the TYNDP 2022 static grid model for Continental Europe and the Baltics [55], [56], [57].

While flow-based market coupling constraints from the main scenarios of this demo will be based on JAO data, this capacity calculation module could support future efforts to generate original flow-based domains for medium term scenarios. This notably includes the possibility to address the impact of advanced network elements on market clearing through the implementation of evolved FB capacity calculation for HVDC links and phase-shift transformers.

3.6.4 Market Clearing

The developed system reproduces the structure of the developments conducted during the FARCROSS project, including a requalification of the market clearing module into a more advanced prototype (TRL 6 to 7), developing all necessary data processing to adapt with the requirements of the Hungarian demo (use case HU03). The workflow is supported by the AMPL programming language [58] and the FICO® Xpress Optimization solver [59].

The different steps reproduce real-life market processes and are presented in the following paragraphs.

3.6.4.1 Prequalification

The model simulates the prequalification process where bids and offers from market participants are gathered based on technical capabilities and grid connection criteria. The model assigns unique identifiers to resources and verifies their eligibility to participate, mirroring the actions of TSOs and creating configurations to be fed into later simulation steps.

3.6.4.2 Order Book Management

Next, the model recreates the order book management stage, initializing zonal balances and cross-zonal capacities to reflect the current market state and aggregating all bids in preparation for matching.

3.6.4.3 Order Matching

The order matching process starts with running a market algorithm that decides which orders are accepted and sets the clearing prices, all while respecting pricing rules, system balance, and network limits. It then calculates the key results needed for the post-matching step. Within a fixed time frame, the model performs an optimisation that integrates generalized congestion pricing in hierarchical bidding zones and resolving grid constraints via shadow prices, all within a framework compatible with the EUPHEMIA algorithm to ensure alignment with established European market designs.

3.6.4.4 Post-Matching

Following matching, the model produces simulated post-matching outputs. It calculates and distributes bid-level results, accepted volumes, and clearing prices. It generates outputs for TSOs and market players and includes timing logic for validation before final settlement.

3.6.4.5 Settlement

Finally, the model simulates the financial realization of market outcomes. Using the matched volumes and clearing prices, it computes settlements and transfers results to a modelled intraday scheduling module. The settlement unit processes simulated payments and reconciles traded energy and flexibility volumes, completing the virtual market cycle.

3.6.5 Key Outputs

The outputs of the market clearing model provide a comprehensive overview of how submitted bids are processed, evaluated, and settled across various energy and balancing markets.

The following outputs are applicable to all types of bid:

- *An acceptance ratio, as a value between 0 and 1 indicating how much of the submitted quantity was accepted in the final market solution.*
- *A bid surplus, which represents the economic benefit (or loss) realized from accepting that bid, expressed in euros.*
- *Where applicable, the allocated quantity (actual volume cleared) is also shown, calculated as the product of the bid quantity and its acceptance ratio.*

For balancing capacity (BC) bids, including upward or downward reserves across multiple products (aFRR, mFRR, RR), the output also provides zone-specific worst-case network loads and shadow prices, which reflect the marginal cost of system constraints, highlighting the required price to relieve congestion.

The model also calculates and outputs clearing results for each market segment, including:

- Market Clearing Prices (MCP) for energy in each bidding zone and time period,
- Commodity Clearing Prices (CCP) at system level,
- Balancing Capacity Prices (UCP/DCP) for upward and downward services by zone and product,
- Net Energy Exports (NEX) showing inter-zonal flows,
- Cross-zonal procurement volumes for both upward and downward BC.

3.7 Simulation Results and KPI Evaluation

Together, these outputs reproduce the information received by market participants on the one hand, showcasing which of their bids were accepted, at what price, and with what impact on their economic position, and system operators on the other hand, making visible the dynamics of grid-wide balances, constraint pricing, and regional procurement dynamics.

This section presents the results of the Hungarian Task 7.3 demonstration for the delivery day of 12 December 2024. The evaluated simulation batch was designed to validate the end-to-end execution of the demonstration workflow, the consistency of the scenario comparisons and the implementation of the HU02 and HU03 KPI calculations across the day-ahead market and the available intraday and sequential market stages. As the assessment covers a single delivery day, the results provide scenario-specific evidence of technical functionality and directional market effects rather than statistically representative estimates of long-term market or power-system impacts, which will be included in the final version of the deliverable.

3.7.1 General assumptions and simulation scope

The simulation results are interpreted through controlled pairwise comparisons. In each comparison, the target and baseline scenarios are selected so that the principal investigated mechanism – market co-optimisation, DLR-adjusted capacity, balancing-capacity bid source, bid forwarding or RAM cascading – can be isolated as far as possible. Where additional scenario characteristics differ, these are explicitly reported in the relevant subsection.

The analysis represents a one-day demonstration and validation exercise. It is suitable for assessing workflow execution, scenario consistency, KPI implementation and the direction of the observed market effects. It is not intended to provide statistically representative estimates of annual welfare impacts, long-term price effects, congestion frequency or system-wide benefits.

Missing scenario stages or unavailable indicators are reported as unavailable and are not interpreted as zero effects. In particular, IDA3 results are only discussed where the required market and network datasets were available. Results affected by incomplete inputs, non-comparable scenario structures or preprocessing assumptions are identified in the corresponding comparison subsection.

3.7.2 Input data and preprocessing simplifications

The source datasets used in the evaluated batch differed in temporal resolution, order representation and file structure. They were therefore transformed into a common internal representation before the scenario runs. The same preprocessing rules were applied to the target and baseline of each pairwise comparison so that the observed differences are attributable primarily to the scenario mechanism being evaluated rather than to inconsistent data treatment.

The following preprocessing steps are relevant to the interpretation of the results:

- Simple-order aggregation: simple orders with the same delivery period, bidding zone and order direction were grouped into predefined 10 EUR/MWh price intervals, and their offered quantities were aggregated.
- Filtering of negligible block orders: small non-exclusive block orders below the configured 1 MWh threshold were removed to reduce the number of binary decision variables.
- Conversion of single-hour block orders: non-exclusive block orders covering only one hour were represented as simple orders because their intertemporal acceptance constraint was not relevant.
- Aggregation of compatible block orders: non-exclusive block orders were aggregated where they had the same bidding zone, direction, price interval and temporal volume profile.
- Temporal-resolution harmonisation: quarter-hourly input products were converted to the temporal representation required by the respective simulation configuration.
- Network-data harmonisation: where a sequential auction stage was supplied with NTC-based network data, the constraints were transformed into a PTDF-compatible representation so that they could be processed by the common market-clearing workflow.

These transformations reduce the computational size of the optimisation problem but may smooth local details of the original order curves and remove economically negligible bids. The results are therefore evaluated primarily through comparisons between scenarios processed with identical rules.

Absolute order counts and highly localized price-curve characteristics should not be interpreted as exact reproductions of the complete operational order books.

3.7.3 KPI evaluation rules

The official KPI values reported in this section are taken directly from the KPI output files generated for the evaluated scenarios. Where a required pairwise sensitivity or mechanism-isolation comparison is not available as a dedicated official KPI output, the corresponding indicator is derived from the processed target and baseline results using the same KPI definition. Such derived indicators are explicitly identified.

HU03-KPI2 values are stored as fractional relative price differences and are multiplied by 100 for percentage presentation. HU02-KPI3 and HU03-KPI4 are stored as ratios and are likewise multiplied by 100 when presented as percentages of beneficial CNECs or market time units. Welfare indicators HU02-KPI4 and HU03-KPI3 are already expressed as percentage changes in the KPI output files and are therefore not multiplied by 100 again. Missing or non-applicable results are reported as “n/a” and are not treated as zero.

HU02-KPI2, Additional RAM, is evaluated at the level of individual CNEC–MTU combinations. The official aggregate value is reported separately as the total additional RAM. CNEC-level values are not accumulated across MTUs unless the source data provide a stable mapping of the physical network elements between the respective time intervals.

HU03-KPI2, Price Difference, is reported separately for each evaluated energy or balancing-capacity product. The product notation used in the result figures is DS1 for downward aFRR, DS2 for downward mFRR, DS3 for downward RR, ES for energy, US1 for upward aFRR, US2 for upward mFRR and US3 for upward RR. Equivalently, DCP/UCP product indices 1, 2 and 3 denote aFRR, mFRR and RR, respectively.

HU02-KPI3 and HU03-KPI4 are reported as percentages of beneficial CNECs and beneficial market time units, respectively. Welfare-related indicators, including HU02-KPI4 and HU03-KPI3, are also reported as percentage changes relative to the corresponding baseline scenario defined in Section 3.5.4.

3.7.4 Scenario comparison results

The following subsections present the controlled scenario comparisons defined in Section 3.5.4. Each comparison identifies the target and baseline configurations, reports the applicable official KPI outputs and interprets the results using supporting market or network diagnostics where these provide additional explanatory value.

3.7.4.1 DAM HU03 co-optimisation (C0a vs A0)

This comparison evaluates the effect of jointly clearing energy and balancing capacity in the day-ahead market. Scenario C0a applies co-optimised clearing using the SLR-based flow-based domain, while A0 represents the corresponding non-co-optimised reference in which the energy and balancing-capacity markets are cleared separately and balancing capacity is not exchanged across bidding zones. The market inputs, delivery day and network-capacity assumptions are otherwise kept consistent, allowing the observed differences to be attributed primarily to the co-optimisation mechanism.

Figure 47 presents the official HU03-KPI2 results. The energy market clearing price remained unchanged relative to A0. The price difference was also marginal for downward aFRR, at -0.92%. More substantial changes occurred in the balancing-capacity products: downward mFRR increased by 136.11%, upward aFRR by 28.70%, and upward mFRR by 69.52%. Valid price-difference values were not available for downward or upward RR and are therefore reported as not applicable rather than as zero.

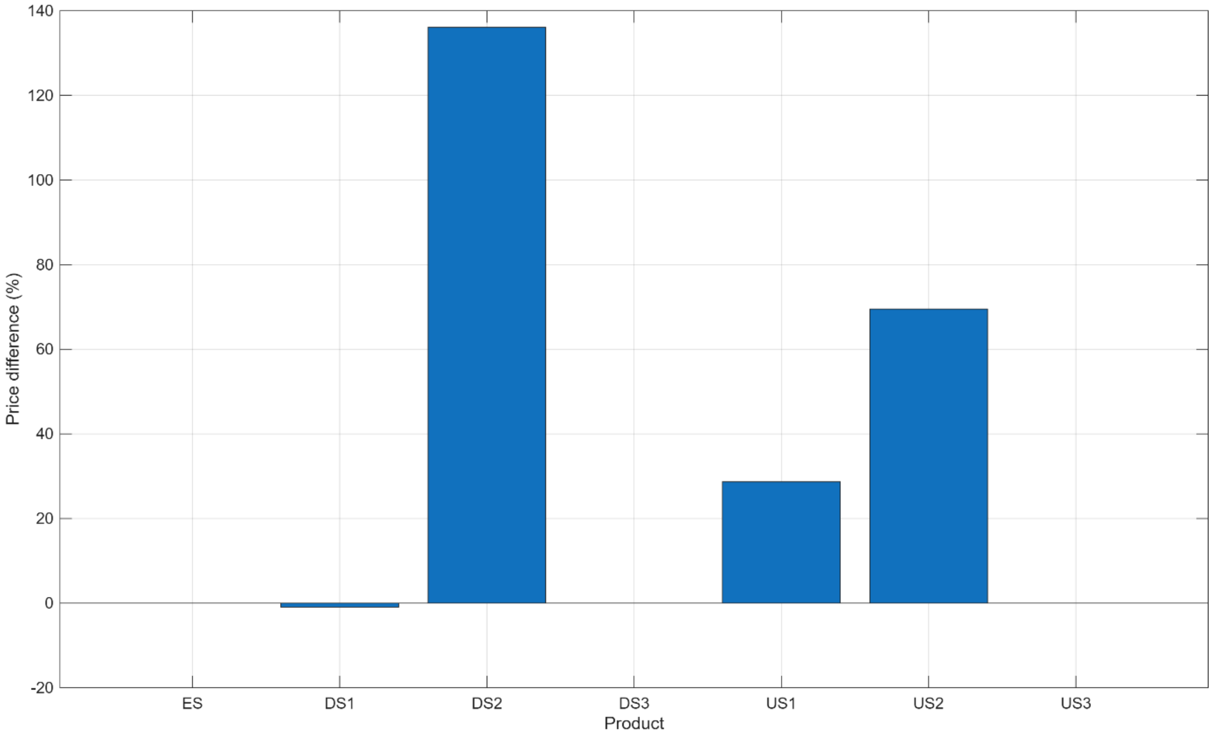


Figure 47. HU03-KPI2 price differences by product for DAM co-optimisation, C0a compared with A0. DS1, DS2 and DS3 denote downward aFRR, mFRR and RR; ES denotes energy; and US1, US2 and US3 denote upward aFRR, mFRR and RR.

The co-optimised case produced an official HU03-KPI3 welfare gain of 0.02% relative to the separated-market reference. HU03-KPI4 indicates that 37.50% of the evaluated market time units were beneficial according to the KPI definition. The welfare result therefore indicates a positive aggregate effect for the evaluated delivery day, although the benefit was not distributed uniformly across all market time units.

Overall, the comparison indicates that the principal effect of day-ahead co-optimisation was observed in balancing-capacity price formation rather than in the energy market clearing price. The particularly large relative differences for the mFRR products should be interpreted together with the corresponding absolute price levels, because relative indicators may become pronounced where baseline prices are low. As the comparison covers one delivery day, the results provide directional evidence of the functioning and potential effect of the co-optimised design rather than a statistically representative estimate of its longer-term market impact.

3.7.4.2 IDA2 HU03 co-optimisation (D0a vs B0)

This comparison evaluates the effect of jointly clearing energy and balancing capacity in the IDA2 intraday auction. Scenario D0a applies co-optimised clearing using the SLR-based flow-based domain, while B0 represents the corresponding non-co-optimised IDA2 reference in which energy and balancing capacity are cleared separately and balancing capacity is not exchanged across bidding zones. The market stage, delivery day and network-capacity assumptions are otherwise kept consistent, allowing the observed differences to be attributed primarily to the co-optimisation mechanism.

Figure 48 presents the official HU03-KPI2 results. The energy market clearing price remained unchanged between D0a and B0. Downward aFRR decreased by 0.92%, while downward mFRR increased by 136.11%. Upward aFRR and upward mFRR increased by 28.70% and 69.52%, respectively. Valid relative price-difference values were not available for downward or upward RR because the corresponding baseline prices did not provide valid non-zero denominators.

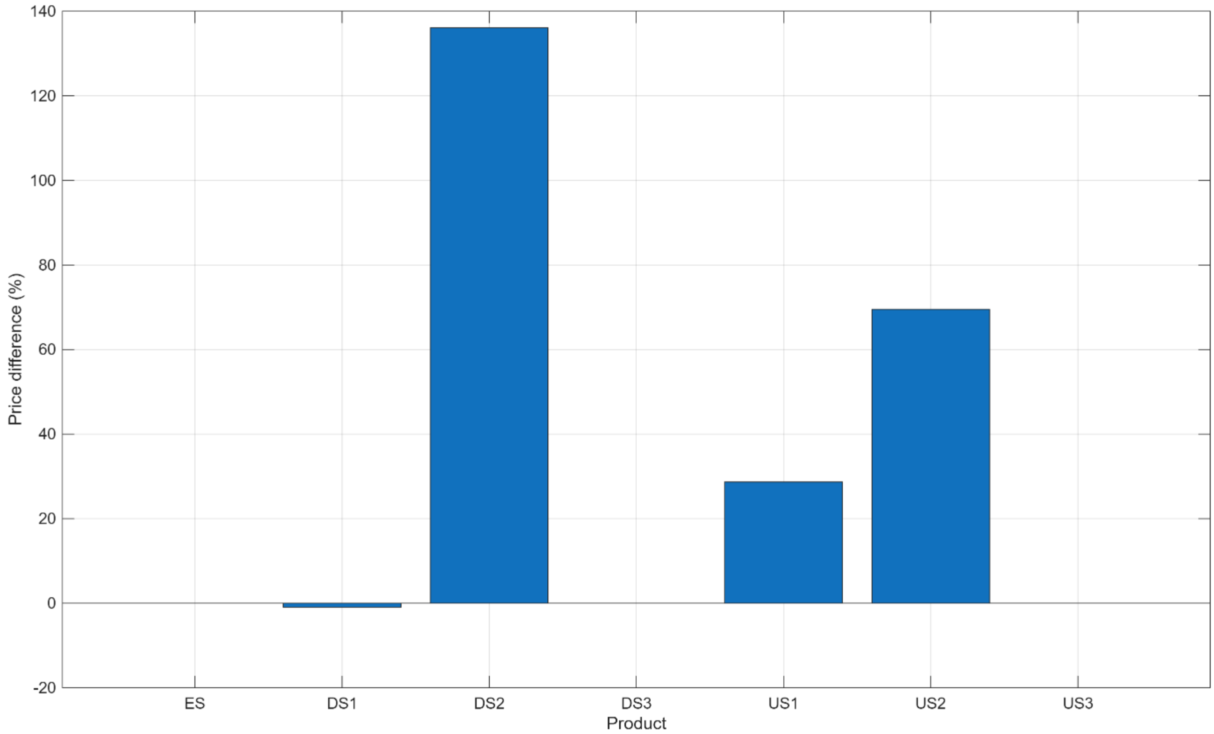


Figure 48. HU03-KPI2 price differences by product for IDA2 co-optimisation, D0a compared with B0. DS1, DS2 and DS3 denote downward aFRR, mFRR and RR; ES denotes energy; and US1, US2 and US3 denote upward aFRR, mFRR and RR.

The product-level HU03-KPI2 values are identical to those obtained for the corresponding DAM comparison. A diagnostic examination of the raw result files confirmed that this equality is not caused by incorrect scenario mapping or copied KPI outputs. The balancing-capacity price vectors are identical between the investigated DAM and IDA2 simulations, and the relative target-to-baseline changes are therefore also identical. Although the absolute DAM and IDA2 energy-price profiles differ from one another, co-optimisation did not change the energy market clearing price relative to the respective baseline in either market stage.

The co-optimised IDA2 case produced an official HU03-KPI3 welfare gain of 0.05% relative to the separated-market reference, compared with 0.02% in the corresponding DAM comparison. HU03-KPI4 indicates that 37.50% of the evaluated market time units were beneficial according to the welfare-based KPI definition. The higher aggregate welfare gain in IDA2 therefore arose despite the identical product-level relative price indicators and reflects differences in the underlying accepted quantities and welfare contributions of the intraday market.

Overall, the comparison indicates that IDA2 co-optimisation produced a positive aggregate welfare effect without changing the energy clearing price relative to B0. Its visible price effects were concentrated in balancing-capacity products. The large relative mFRR values should not be interpreted as equivalent increases in absolute procurement expenditure, because HU03-KPI2 is an unweighted mean of relative zone–MTU price changes and excludes observations with zero baseline prices. The result supports the technical functioning and potential economic relevance of IDA2 co-optimisation for the evaluated delivery day, but it does not constitute a statistically representative longer-term estimate.

3.7.4.3 DAM HU02 DLR (C2a vs C0a)

This comparison isolates the effect of applying DLR-adjusted Remaining Available Margin values in the day-ahead co-optimised market calculation. Scenario C2a uses the DLR-enhanced flow-based domain, while C0a uses the corresponding SLR-based domain. The energy and balancing-capacity bids, market-clearing formulation and delivery day are otherwise unchanged. Consequently, the comparison reflects the incremental effect of the DLR-based network-capacity adjustment.

The official HU02-KPI2 result reports 781,044 MW of total additional RAM across the evaluated CNEC–MTU records. Figure 49 shows the distribution of this additional RAM over the 24 market time units. Positive additional RAM was reported in every evaluated MTU, although its magnitude varied substantially throughout the day. The largest values occurred during the first three MTUs and around MTUs 10–12, while the lowest values occurred around MTUs 7 and 21.

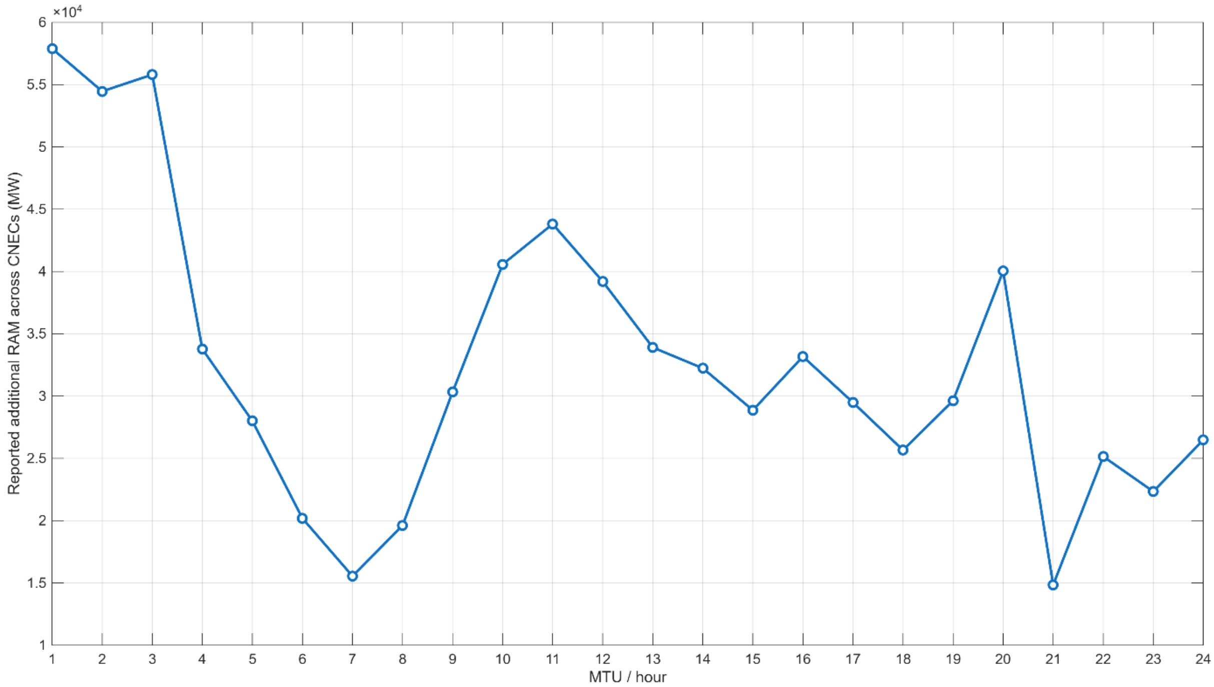


Figure 49. HU02-KPI2 reported additional RAM by market time unit for the DAM DLR comparison, C2a compared with C0a. Values represent the sum of the reported additional RAM across CNECs within each MTU.

HU02-KPI3 indicates that 0.75% of the evaluated CNECs were beneficial according to the official KPI definition. The relatively low ratio shows that the additional RAM was concentrated on a limited subset of the evaluated network constraints rather than being distributed uniformly across the complete CNEC set.

HU02-KPI4 reports an additional welfare result of 0.00% at the available reporting precision. The DLR-enhanced capacity domain therefore increased the reported network margins but did not produce a measurable welfare improvement in the corresponding market-clearing result for the evaluated delivery day. This is technically plausible: additional RAM affects the market outcome only where the modified constraints are binding, or sufficiently close to binding, in the welfare-maximising solution.

The result demonstrates a clear capacity-domain effect but no corresponding economic effect in this specific one-day DAM case. The aggregated value of 781,044 MW must not be interpreted as a simultaneously available cross-zonal transfer capacity. It is the sum of additional RAM values over multiple CNEC–MTU observations. Furthermore, because the available data do not provide a stable physical mapping of every CNEC identifier between MTUs, CNEC-level values are not accumulated across time in the interpretation.

3.7.4.4 IDA2 HU02 DLR (D2a vs D0a)

This comparison isolates the effect of applying DLR-adjusted Remaining Available Margin values in the co-optimised IDA2 market calculation. Scenario D2a uses the DLR-enhanced flow-based domain, while D0a uses the corresponding SLR-based domain. The energy and balancing-capacity bids, market-clearing formulation, market stage and delivery day are otherwise unchanged. The comparison therefore represents the incremental effect of the DLR-based capacity adjustment.

The official HU02-KPI2 result reports 736,568 MW of total additional RAM across the evaluated CNEC–MTU records. Figure 50 presents the additional RAM aggregated within each market time unit. Positive additional RAM was reported throughout the evaluated day, although the magnitude varied considerably between MTUs. This confirms that the DLR-enhanced domain increased the available margin represented in the IDA2 capacity constraints.

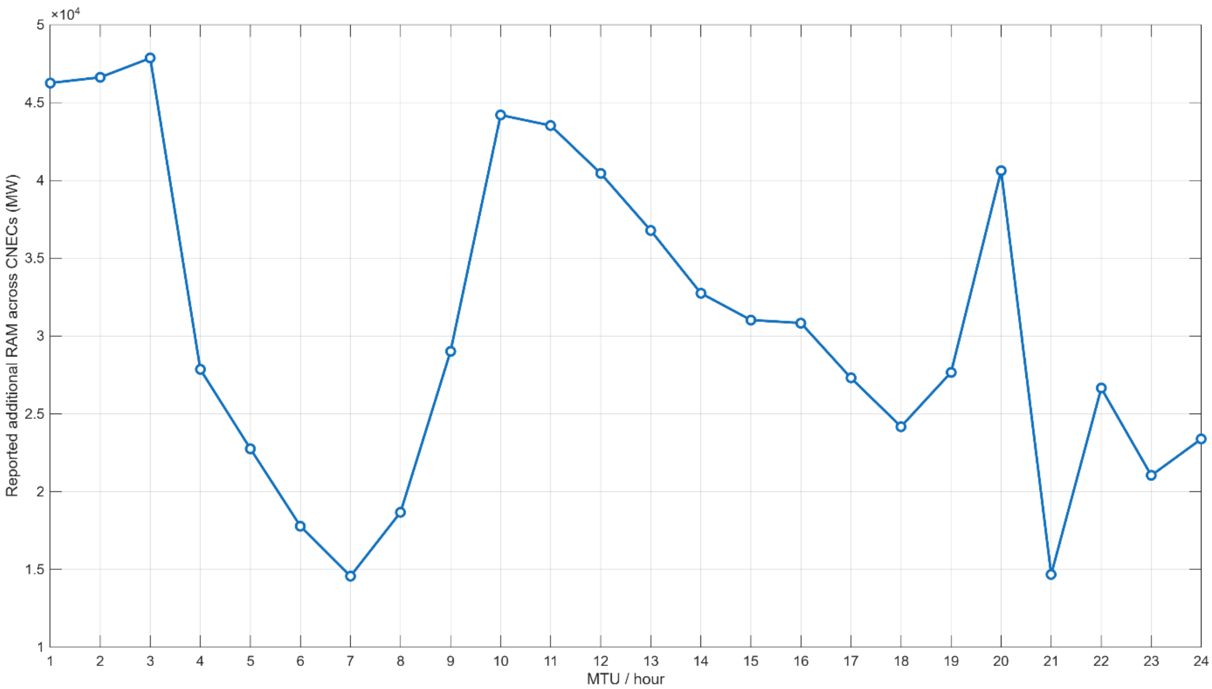


Figure 50. HU02-KPI2 reported additional RAM by market time unit for the IDA2 DLR comparison, D2a compared with D0a. Values represent the sum of reported additional RAM across CNECs within each MTU.

HU02-KPI3 indicates that 0.98% of the evaluated CNECs were beneficial according to the official KPI definition. Although this ratio is slightly higher than the 0.75% obtained in the corresponding DAM comparison, it remains low in relation to the complete evaluated CNEC set. The additional capacity was therefore concentrated on a relatively limited subset of network constraints.

HU02-KPI4 reports an additional welfare result of 0.00% at the available reporting precision. The DLR-adjusted capacity domain consequently produced a clear change in the network-capacity inputs but no measurable change in the resulting IDA2 welfare for the evaluated delivery day. This indicates that the modified constraints were either non-binding in the market-clearing solution or that the additional margins were not sufficient to alter the optimal accepted bids and zonal market outcome.

The IDA2 result therefore demonstrates a capacity-domain effect without a corresponding measurable economic effect in this specific simulation. The reported total of 736,568 MW is an aggregate over multiple CNEC–MTU observations and must not be interpreted as simultaneously available cross-zonal transfer capacity. CNEC-level results are not accumulated across MTUs because the available identifiers do not provide a stable physical mapping of all network elements over time.

3.7.4.5 DAM BC bid source (C0b vs C0a)

This comparison evaluates the sensitivity of the co-optimised day-ahead market result to the source of Hungarian balancing-capacity supply bids. Scenario C0b uses balancing-capacity bids derived from the ENTSO-E Transparency Platform, while C0a uses the original HUPX Labs/MAVIR input set. Both scenarios use the same energy-market inputs, SLR-based flow-based domain and co-optimised market-clearing formulation. The observed differences therefore primarily reflect the change in the Hungarian balancing-capacity bid dataset and its associated preprocessing.

Figure 51 presents the relative product-price differences calculated for C0b compared with C0a using the HU03-KPI2 calculation method. The energy market clearing price remained unchanged. The mean relative price difference was −100.00% for downward aFRR and −95.56% for downward mFRR. Upward aFRR and upward mFRR decreased by 8.54% and 5.21%, respectively. Valid relative price-difference values were not available for downward or upward RR because the corresponding baseline records did not provide valid non-zero denominators.

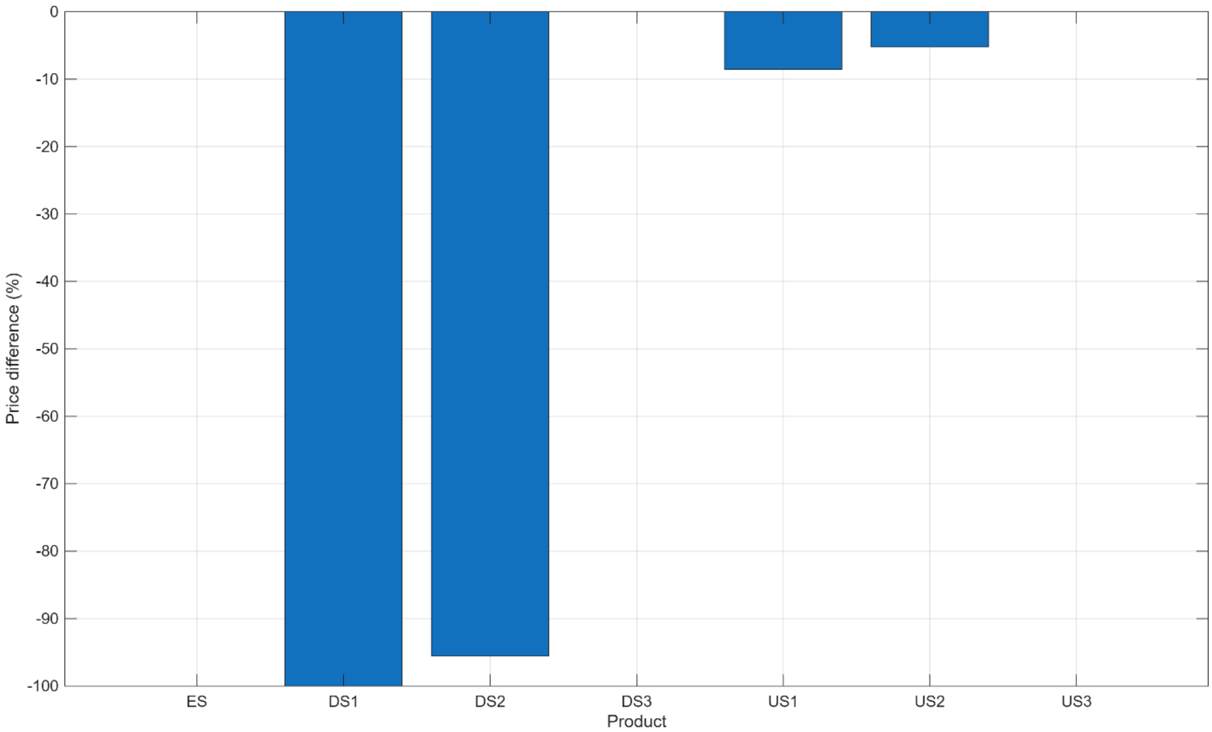


Figure 51. Relative price differences by product for the DAM balancing-capacity bid-source sensitivity comparison, C0b compared with C0a.

The aggregate welfare result decreased by 7.11% relative to C0a, and the beneficial-hours ratio was 0.00%. For the evaluated delivery day, replacing the HUPX Labs/MAVIR balancing-capacity input set with the ENTSO-E-derived dataset therefore produced no beneficial market time units according to the welfare-based indicator.

The comparison demonstrates that the co-optimised market outcome is materially sensitive to the representation of balancing-capacity supply. Although most balancing-capacity price indicators decreased, this did not translate into a welfare improvement. Lower clearing-price indicators alone are therefore insufficient to evaluate the alternative dataset, as the resulting welfare also depends on offered volumes, bid-curve structure, accepted quantities and the interaction between energy and balancing-capacity procurement.

These results should be interpreted as a data-input sensitivity test rather than as evidence that either source provides a generally superior representation of the Hungarian balancing-capacity market. The datasets differ in their origin and preprocessing, and the comparison covers only one delivery day. The large downward-product percentages must also be read with caution because the indicator is an unweighted mean of relative zone-MTU changes and excludes records with zero baseline prices. In particular, the -100.00% DS1 result is an aggregate relative indicator and does not by itself establish that every downward-aFRR price observation decreased to zero.

3.7.4.6 IDA2 BC bid source (D0b vs D0a)

This comparison evaluates the sensitivity of the co-optimised IDA2 result to the source of Hungarian balancing-capacity supply bids. Scenario D0b uses balancing-capacity bids derived from the ENTSO-E Transparency Platform, while D0a uses the original HUPX Labs/MAVIR input set. Both scenarios use the same energy-market inputs, SLR-based flow-based domain and co-optimised market-clearing formulation. The observed differences therefore primarily reflect the alternative representation and preprocessing of Hungarian balancing-capacity bids.

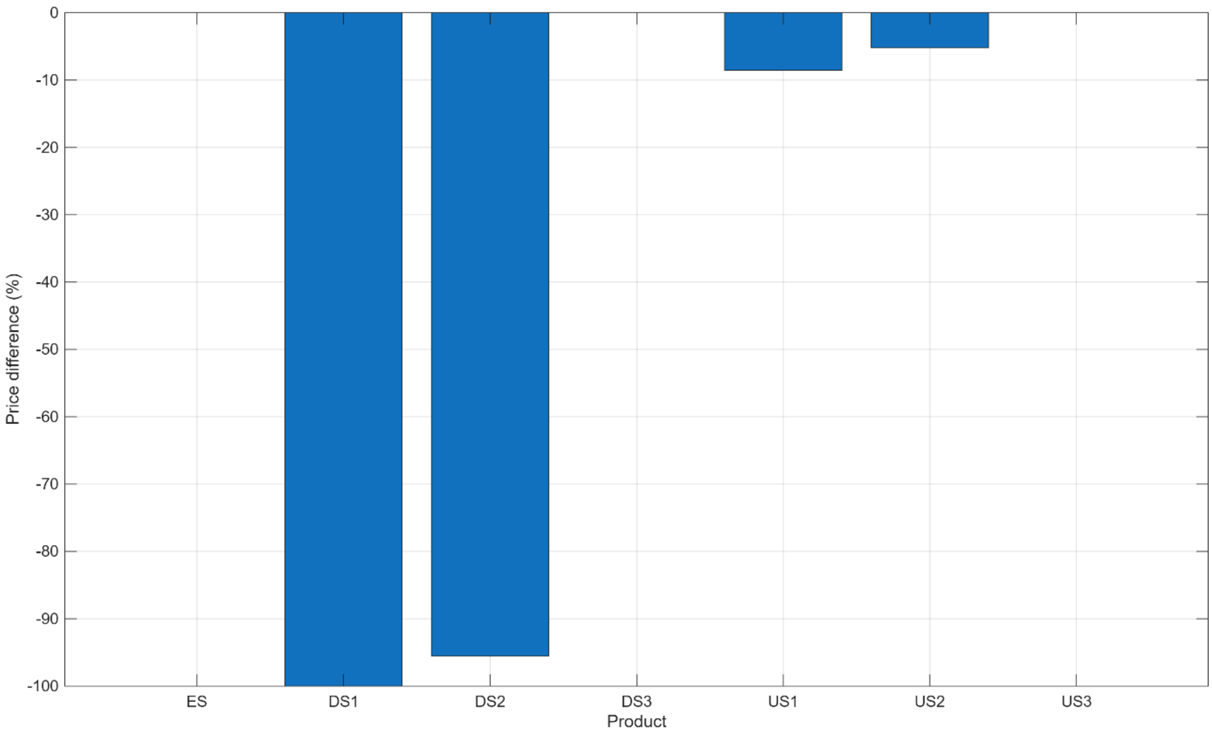


Figure 52. Relative price differences by product for the IDA2 balancing-capacity bid-source sensitivity comparison, D0b compared with D0a.

Figure 52 presents the relative product-price differences calculated for D0b compared with D0a using the HU03-KPI2 method. The energy market clearing price remained unchanged. The mean relative price difference was −100.00% for downward aFRR and −95.56% for downward mFRR. Upward aFRR and upward mFRR decreased by 8.54% and 5.21%, respectively. Valid relative price-difference values were not available for downward or upward RR because the corresponding baseline observations did not provide valid non-zero denominators.

The aggregate welfare result decreased by 18.13% relative to D0a, while the beneficial-hours ratio was 0.00%. Consequently, none of the evaluated market time units was classified as beneficial according to the welfare-based KPI definition. The welfare decrease was also substantially larger than the 7.11% reduction observed in the corresponding DAM bid-source comparison.

The result indicates that the IDA2 co-optimisation outcome is highly sensitive to the balancing-capacity bid dataset. Although the alternative ENTSO-E-derived input produced lower relative balancing-capacity price indicators, it also resulted in a considerable deterioration in aggregate welfare. This demonstrates that lower clearing-price indicators cannot be interpreted independently of the available bid volumes, bid-curve structure, accepted quantities and the interaction between energy and balancing-capacity procurement.

The comparison should therefore be interpreted as an input-data sensitivity assessment rather than as evidence that either dataset is generally preferable. The ENTSO-E-derived and HUPX Labs/MAVIR datasets differ in source coverage and preprocessing, and the evaluation covers only one delivery day. In addition, the large downward-product percentages are unweighted means of relative zone–MTU changes and exclude observations with zero baseline prices. They do not directly represent changes in total balancing-capacity procurement expenditure.

3.7.4.7 IDA2 bid forwarding (H0c/IDA2 vs D0a)

This comparison evaluates the effect of forwarding unaccepted bids between successive intraday auctions. The IDA2 output of scenario H0c includes residual bids forwarded from IDA1, while D0a represents the corresponding standalone co-optimised IDA2 calculation without bid forwarding. Both cases use the SLR-based flow-based domain, and RAM is not cascaded between the auctions in H0c. The comparison therefore primarily isolates the effect of the additional residual liquidity entering IDA2.

Figure 53 presents the official HU03-KPI2 results. Compared with D0a, the mean relative price difference was −100.00% for downward aFRR and −100.00% for downward mFRR. The energy market clearing price decreased by 29.87%, while upward aFRR and upward mFRR decreased by 4.10% and 3.13%, respectively. Valid relative price-difference values were not available for downward or upward RR because the corresponding baseline observations did not provide valid non-zero denominators.

The official HU03-KPI3 result indicates a welfare gain of 0.16% relative to the standalone D0a case. HU03-KPI4 reports a beneficial-hours ratio of 100.00%, meaning that every evaluated market time unit was classified as beneficial according to the welfare-based KPI definition.

The results indicate that forwarding residual bids from IDA1 materially changed price formation and improved aggregate welfare in IDA2 for the evaluated delivery day. The simultaneous reduction in the energy-price indicator and the positive welfare result is consistent with the additional bids improving the effective liquidity and allocation opportunities available to the co-optimised market calculation. The beneficial outcome across all evaluated market time units further indicates that the aggregate welfare improvement was not limited to only a small part of the day.

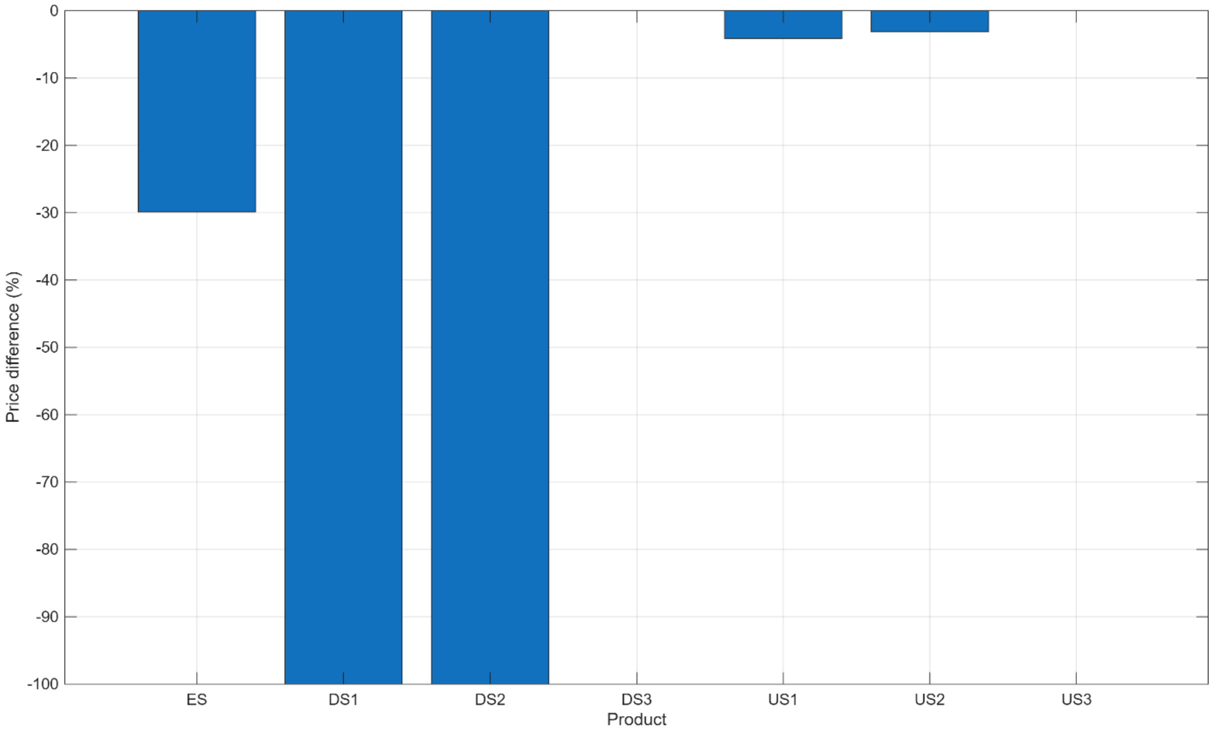


Figure 53. HU03-KPI2 price differences by product for the IDA2 bid-forwarding comparison, using the IDA2 output of H0c compared with D0a.

The large downward-balancing price differences must nevertheless be interpreted as mean relative changes rather than as changes in total procurement expenditure. HU03-KPI2 excludes observations with zero baseline prices, and a value of −100.00% does not by itself describe the absolute price level, accepted volume or procurement cost. Confirmation of the liquidity mechanism therefore depends on the corresponding accepted- and remaining-order outputs. As the result represents one delivery day, it demonstrates the potential effect of bid forwarding within the implemented workflow but does not establish a representative long-term market impact.

3.7.4.8 IDA2 RAM cascading (G0a/IDA2 vs D0a)

This comparison evaluates the effect of sequentially updating the available network capacity between market stages. The IDA2 output of scenario G0a uses the residual RAM remaining after the preceding DAM and IDA1 clearings, while D0a represents the corresponding standalone co-optimised IDA2 calculation using the original SLR-based flow-based domain. Market orders are not forwarded in G0a. The comparison was designed to isolate the effect of RAM cascading on the IDA2 market outcome. However, as discussed in Section 3.7.4.13, G0a already differs from the standalone reference at the initial DAM stage; the comparison therefore represents the observed effect of the complete G0a configuration rather than a perfectly isolated RAM-cascading effect.

Figure 54 presents the official HU03-KPI2 results. Compared with D0a, the mean relative price difference was −3.76% for downward aFRR and −2.55% for downward mFRR. The energy market clearing price decreased marginally by 0.11%, while upward aFRR and upward mFRR decreased by 0.06% and 1.86%, respectively. Valid relative price-difference values were not available for downward or upward RR because the corresponding baseline observations did not provide valid non-zero denominators.

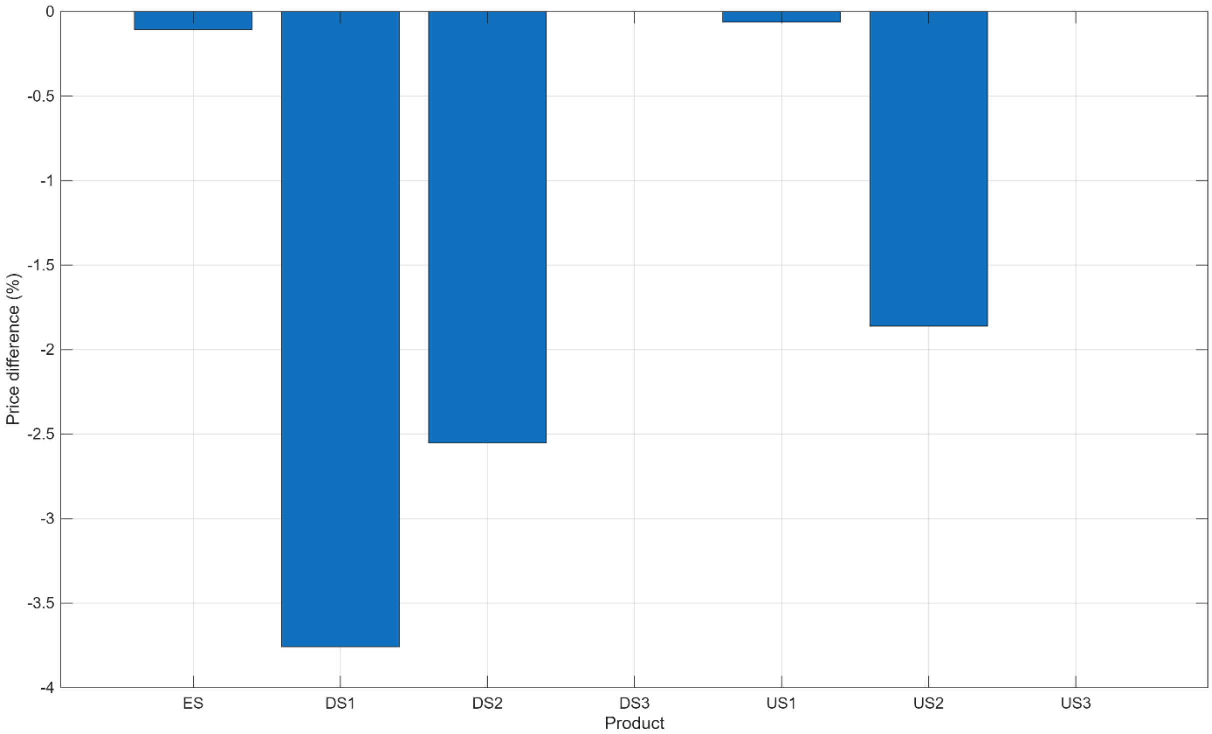


Figure 54. HU03-KPI2 price differences by product for IDA2 RAM cascading, using the IDA2 output of G0a compared with D0a.

HU03-KPI3 reports an additional welfare result of 0.00% at the available reporting precision. HU03-KPI4 gives a beneficial-hours ratio of 4.17%, corresponding to one of the 24 evaluated market time units. The sequential RAM update therefore changed several energy and balancing-capacity price indicators, but it did not produce a measurable aggregate welfare improvement for the evaluated delivery day.

The product-level price effects were substantially smaller than those observed for bid forwarding. This indicates that, in the evaluated IDA2 case, updating the network constraints using residual RAM had a limited market impact when no residual orders were forwarded from preceding auctions. The small negative price differences should not automatically be interpreted as an economic improvement, because the price indicator does not account for changes in accepted quantities, procurement costs or the distribution of welfare between market participants.

The comparison was designed to isolate the effect of RAM cascading on the IDA2 outcome. However, the DAM-stage consistency check in Section 3.7.4.13 shows that G0a already differs from C0a before residual RAM is transferred. The results must therefore be interpreted as the observed effect of the G0a sequential configuration rather than as a perfectly isolated RAM-cascading effect. A fuller interpretation of the mechanism requires the corresponding RAM-left, constraint-utilisation, binding-constraint and shadow-price outputs. The present result covers one delivery day and therefore provides evidence of workflow functionality and scenario-specific behaviour rather than a representative estimate of the longer-term value of RAM cascading.

3.7.4.9 IDA2 combined sequential (I0c/IDA2 vs D0a)

This comparison evaluates the combined effect of bid forwarding and RAM cascading in the IDA2 market. In scenario I0c, unaccepted bids and the residual RAM remaining after earlier auction stages are both transferred through the sequential DAM–IDA workflow. Scenario D0a represents the standalone co-optimised IDA2 calculation without either sequential mechanism. Both configurations originate from the SLR-based capacity framework, but the I0c result reflects the cumulative effect of the preceding auction stages. The comparison therefore measures the joint effect of the two sequential mechanisms rather than isolating either mechanism individually.

Figure 55 presents the official HU03-KPI2 results. Compared with D0a, the mean relative price difference was −99.50% for downward aFRR and −100.00% for downward mFRR. The energy market clearing price decreased by 29.79%, while upward aFRR and upward mFRR decreased by 0.50% and 0.98%, respectively. Valid relative price-difference values were not available for downward or upward RR because the corresponding baseline observations did not provide valid non-zero denominators.

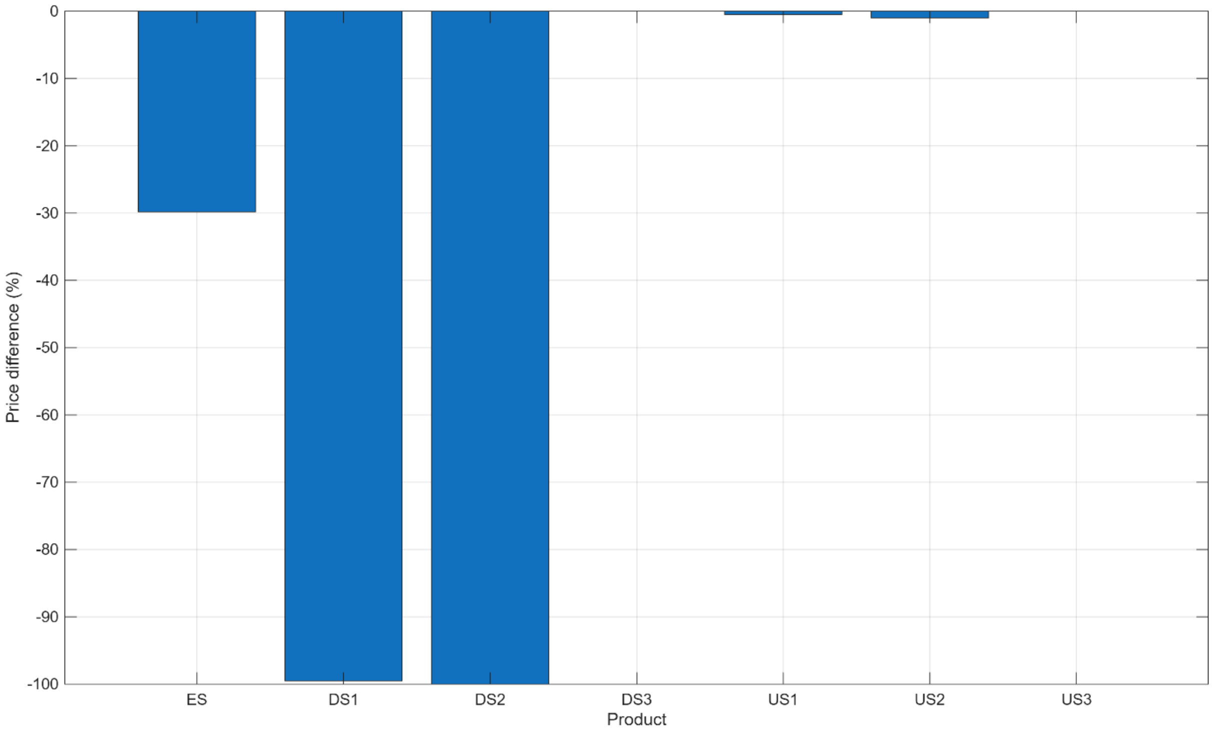


Figure 55. HU03-KPI2 price differences by product for combined sequential operation in IDA2, using the IDA2 output of I0c compared with D0a.

The official HU03-KPI3 result indicates a welfare gain of 0.15% relative to the standalone D0a case. HU03-KPI4 reports a beneficial-hours ratio of 100.00%, meaning that every evaluated market time unit was classified as beneficial according to the welfare-based KPI definition.

The combined sequential configuration therefore materially changed price formation and produced a positive but modest aggregate welfare effect in the evaluated IDA2 case. The reduction in the energy-price indicator and the positive welfare change are consistent with the sequential process providing both additional residual liquidity and an updated representation of the available network capacity.

The magnitude and pattern of the results are close to those obtained for bid forwarding without RAM cascading. The bid-forwarding-only scenario H0c produced a 0.16% welfare gain and the same 100.00% beneficial-hours ratio, whereas the combined I0c case produced a 0.15% welfare gain. This suggests that bid forwarding was the dominant contributor to the combined effect for the evaluated day, while RAM cascading provided only a limited additional contribution. The dedicated add-on comparisons in Sections 3.7.4.10 and 3.7.4.11 are used to examine this interpretation more directly.

The large downward-balancing price differences remain mean relative changes across valid zone–MTU observations and should not be interpreted as equivalent changes in total procurement expenditure. Observations with zero baseline prices are excluded from HU03-KPI2, and the indicator does not incorporate accepted volumes or procurement costs directly. The result therefore demonstrates the scenario-specific potential of combined sequential operation, but it does not provide a representative estimate of its longer-term market impact.

3.7.4.10 IDA2 cascading add-on (I0C/IDA2 vs. H0c/IDA2)

This comparison isolates the incremental effect of RAM cascading when bid forwarding is already active. Scenario I0c transfers both unaccepted bids and residual RAM between successive market stages, while H0c transfers unaccepted bids but does not cascade the remaining network capacity. The comparison uses the IDA2 outputs of the two sequential scenarios. Consequently, differences between them primarily reflect the addition of the RAM-cascading mechanism.

Figure 56 presents the relative product-price differences calculated for the IDA2 output of I0c compared with the IDA2 output of H0c using the HU03-KPI2 method. The energy market clearing price decreased marginally by 0.09%, while upward aFRR and upward mFRR increased by 5.75% and 3.19%, respectively. Valid relative price-difference values were not available for the downward balancing-capacity products or for upward and downward RR because the baseline results did not provide valid non-zero denominators for these product-level calculations.

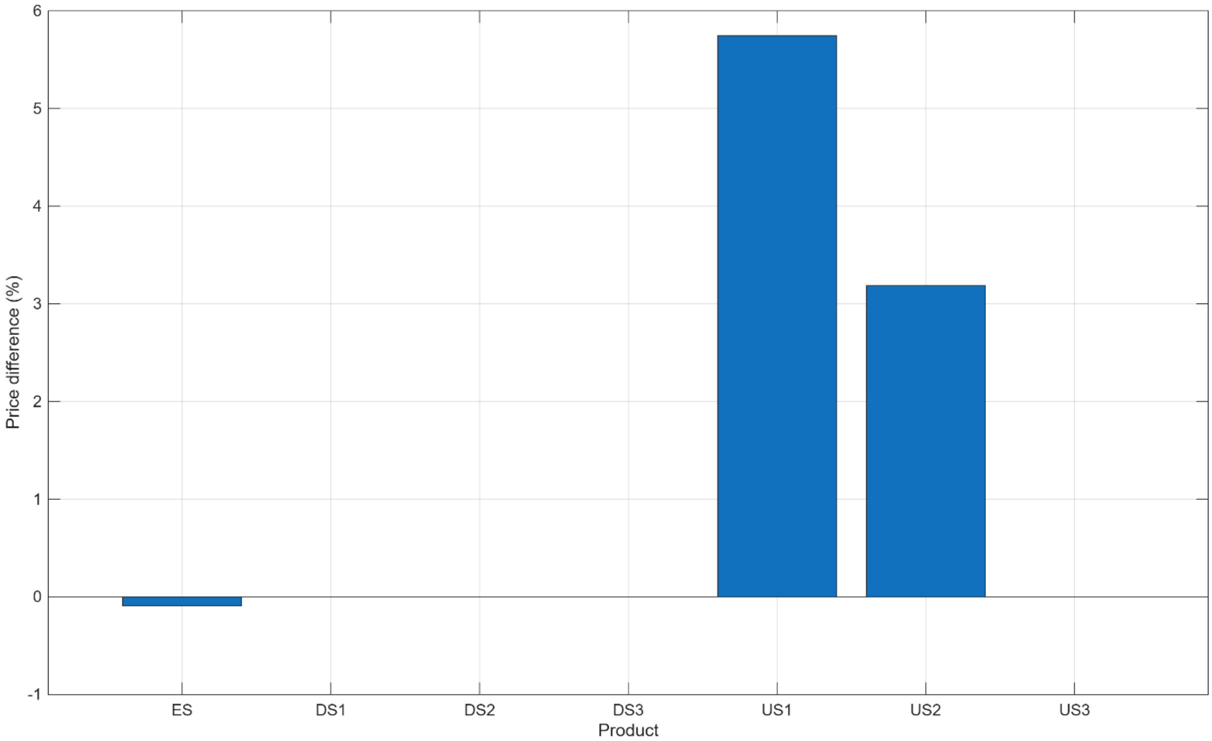


Figure 56. Relative price differences by product for the IDA2 RAM-cascading add-on, using the IDA2 output of I0c compared with the IDA2 output of H0c.

The derived aggregate welfare change was −0.0052%, indicating that adding RAM cascading to the bid-forwarding sequence produced practically no change in total welfare for the evaluated delivery day. The beneficial-hours ratio was 29.17%, corresponding to seven of the 24 evaluated market time units. The mechanism therefore produced locally favourable outcomes during part of the day, but these changes did not result in a positive aggregate welfare effect.

The limited welfare effect is consistent with the broader comparison results. Bid forwarding alone produced a welfare gain of 0.16% relative to the standalone IDA2 case, while the combined sequential scenario produced a gain of 0.15% relative to the same reference. The direct I0c–H0c comparison confirms that the addition of RAM cascading did not materially improve the aggregate result once residual-order forwarding was already active.

The increase in the upward balancing-capacity price indicators should not be interpreted independently as a deterioration or an improvement. These indicators are unweighted means of relative price changes across valid zone–MTU observations and do not directly capture procurement volumes, total costs or welfare distribution. In addition, the absence of valid downward-product indicators limits the completeness of the price-based assessment. The principal conclusion from this comparison is therefore that RAM cascading had only a marginal incremental economic effect in the evaluated IDA2 sequence, although it changed individual price outcomes and produced beneficial results in a subset of market time units.

3.7.4.11 IDA2 forwarding add-on (I0c/IDA2 vs G0a/IDA2)

This comparison isolates the incremental effect of bid forwarding when RAM cascading is already active. Scenario I0c transfers both unaccepted bids and residual RAM between successive auction stages, while G0a transfers residual RAM but does not forward unaccepted market bids. The comparison uses the IDA2 outputs of the two sequential scenarios. Differences between them therefore primarily reflect the additional residual liquidity introduced through bid forwarding.

Figure 57 presents the relative product-price differences calculated for the IDA2 output of I0c compared with the IDA2 output of G0a using the HU03-KPI2 method. The mean relative price difference was −99.49% for downward aFRR and −100.00% for downward mFRR. The energy market clearing price decreased by 29.44%, while upward aFRR and upward mFRR increased by 1.62% and 4.05%, respectively. Valid relative price-difference values were not available for downward or upward RR because the corresponding baseline observations did not provide valid non-zero denominators.

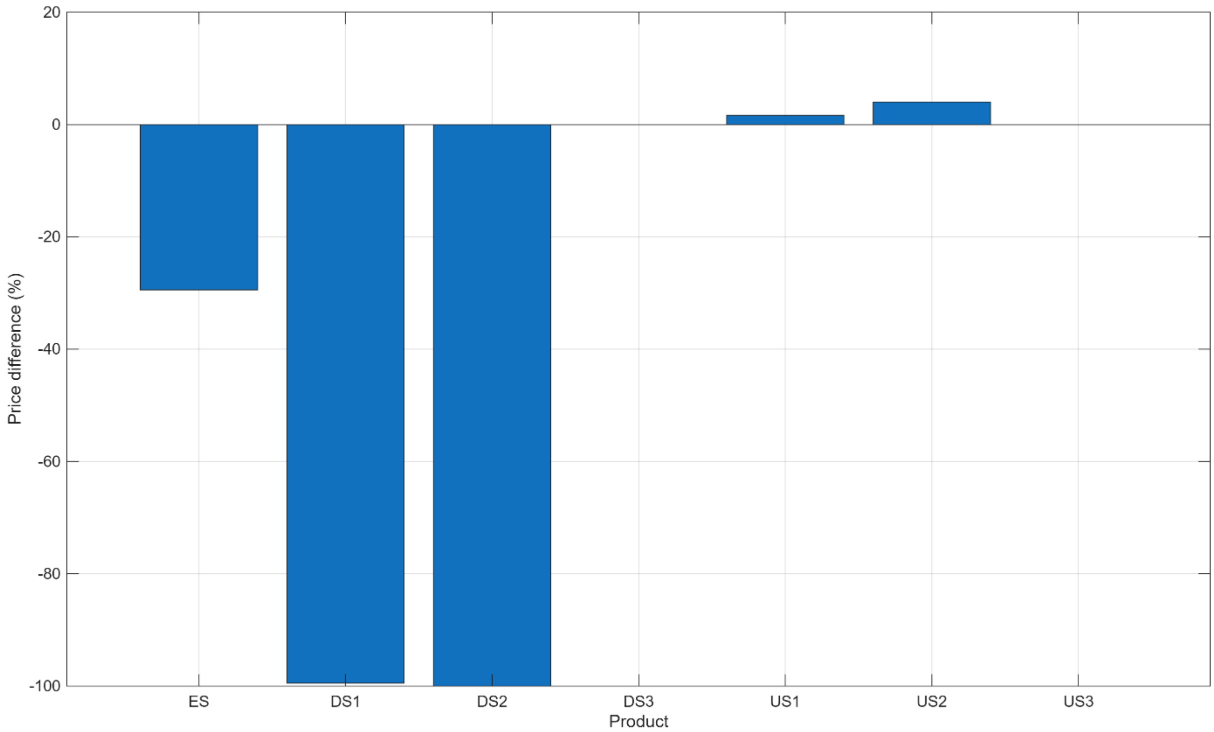


Figure 57. Relative price differences by product for the IDA2 bid-forwarding add-on, using the IDA2 output of I0c compared with the IDA2 output of G0a.

The derived aggregate welfare change was +0.503%, while the beneficial-hours ratio was 100.00%. All 24 evaluated market time units were therefore classified as beneficial according to the welfare-based indicator.

The comparison indicates that bid forwarding was the principal driver of the market changes observed in the combined sequential configuration. Adding residual orders to the RAM-cascading sequence materially reduced the energy-price indicator and the downward balancing-capacity price indicators, while producing a positive aggregate welfare effect throughout the evaluated day. This contrasts with RAM cascading alone, which produced only limited price changes and no measurable welfare improvement at the available reporting precision.

The large downward-product changes should nevertheless be interpreted as mean relative price differences rather than as equivalent reductions in balancing-capacity procurement expenditure. HU03-KPI2 excludes records with zero baseline prices and does not directly account for accepted quantities or total procurement costs. The positive welfare result supports the interpretation that additional residual liquidity improved the IDA2 outcome in this simulation, but the magnitude remains specific to the evaluated delivery day.

The welfare and beneficial-hours values in this comparison were calculated directly from the target and baseline output files rather than taken from an official scenario-specific KPI file. They should therefore be identified as derived pairwise indicators calculated according to the corresponding KPI definitions.

Because G0a does not pass the initial DAM-stage consistency check, the derived +0.503% welfare difference should be treated as indicative rather than as a perfectly isolated bid-forwarding effect. The comparison includes both the addition of bid forwarding and the unresolved initial-stage difference of the G0a sequence.

3.7.4.12 DAM bid-forwarding sequence consistency (H0c/DAM vs C0a)

This comparison checks whether the initial DAM stage of the sequential bid-forwarding scenario H0c reproduces the corresponding standalone co-optimised DAM scenario C0a. Both calculations use the same energy and balancing-capacity inputs, the same SLR-based flow-based domain and the same co-optimised market-clearing formulation. Because bid forwarding only transfers unaccepted bids from one completed auction to a subsequent auction, it should not affect the first DAM stage of the sequence.

The reported HU03-KPI2 values are 0.00% for energy, downward aFRR, downward mFRR, upward aFRR and upward mFRR. Downward and upward RR remain not applicable because no valid relative price-difference values were available. HU03-KPI3 also reports a welfare difference of 0.00%, while the welfare-based beneficial-hours ratio is 0.00%.

These results show that, at the level of the reported KPIs, the DAM output of H0c reproduces the standalone C0a result. This confirms that the preprocessing and market-clearing inputs used at the start of the bid-forwarding sequence are consistent with the standalone reference calculation. The market effects observed in the later H0c auction stages can therefore be attributed to the sequential forwarding of residual bids rather than to an unintended difference already present in the DAM result.

The zero beneficial-hours ratio should not be interpreted as an adverse result in this comparison. Since the target and baseline welfare values are identical, no market time unit has a strictly positive welfare difference. Here, zero differences represent successful consistency rather than an absence of technical value.

3.7.4.13 DAM RAM cascading (G0a/DAM vs C0a)

This comparison checks whether the initial DAM stage of the RAM-cascading scenario G0a reproduces the corresponding standalone co-optimised DAM scenario C0a. Both calculations are expected to use the same market inputs, SLR-based flow-based domain and co-optimised clearing formulation. Because residual RAM can only be calculated and transferred after completion of the first auction, RAM cascading should not yet affect the initial DAM result.

Contrary to this expectation, the DAM output of G0a differs materially from C0a. Figure 58 shows mean relative price differences of +41.67% for downward aFRR, 0.00% for downward mFRR, +0.35% for energy, +53.82% for upward aFRR and 0.00% for upward mFRR. Valid values were not available for downward or upward RR.

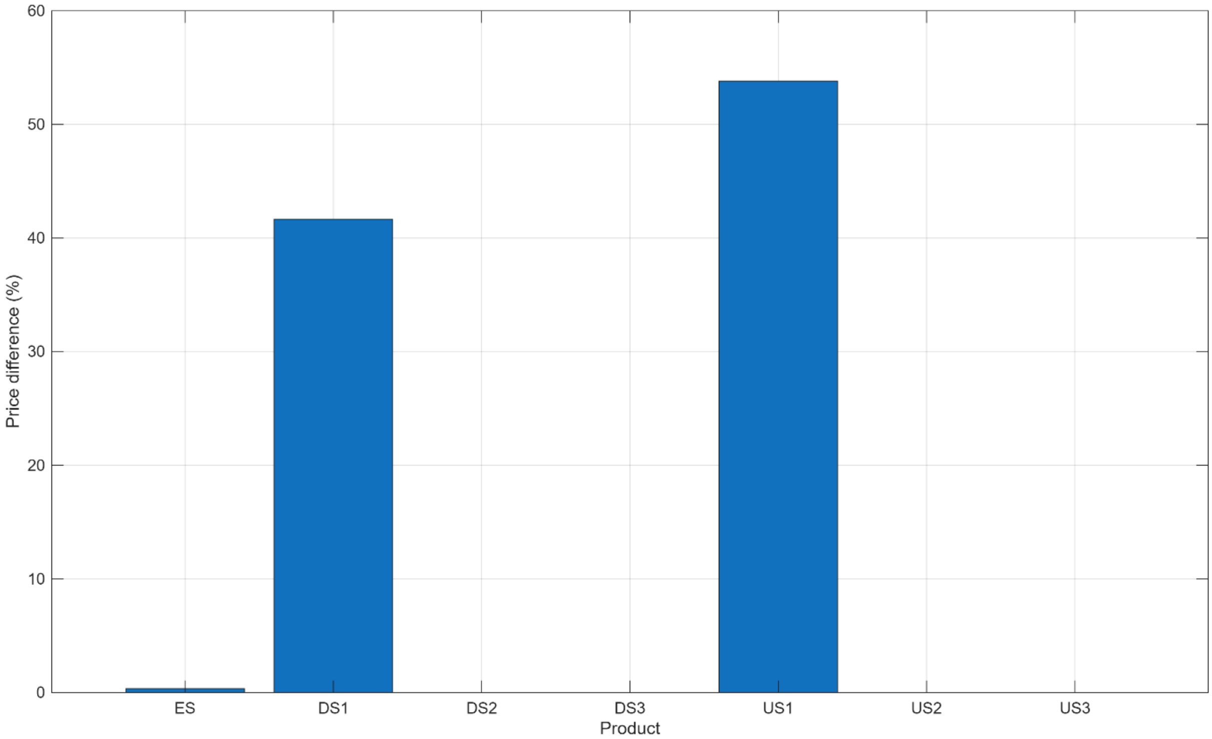


Figure 58. DAM-stage price consistency check for the RAM-cascading sequence, comparing the DAM output of G0a with C0a.

The reported aggregate welfare difference is −6.69%, and the beneficial-hours ratio is 0.00%. The DAM stage of G0a therefore does not reproduce the standalone C0a reference at either the price or welfare level. Unlike the exact consistency observed for the DAM stage of the bid-forwarding sequence, this comparison does not pass the expected initial-stage consistency check.

These differences cannot be interpreted as the economic effect of RAM cascading, because the cascading mechanism should only influence auctions following the initial DAM clearing. They instead indicate that another difference is present between the standalone and sequential DAM calculations, such as scenario initialisation, input transformation, network-data preparation or market-data processing. The available result files establish the discrepancy but do not identify its precise cause.

Consequently, the later IDA2 comparison involving G0a must be interpreted with caution. The IDA2 output reflects not only the transfer of residual RAM but also the effect of beginning the sequence from a DAM result that already differs from the standalone reference. The G0a–D0a comparison therefore does not provide a perfectly isolated estimate of the RAM-cascading effect until the DAM-stage discrepancy is explained.

Figure 59 provides an MTU-level diagnostic of the G0a DAM-stage inconsistency. Welfare is lower than in C0a in every evaluated MTU, while non-zero balancing-capacity price differences occur throughout most of the day. The discrepancy is therefore systematic across the evaluated period rather than being caused by a single isolated market time unit.

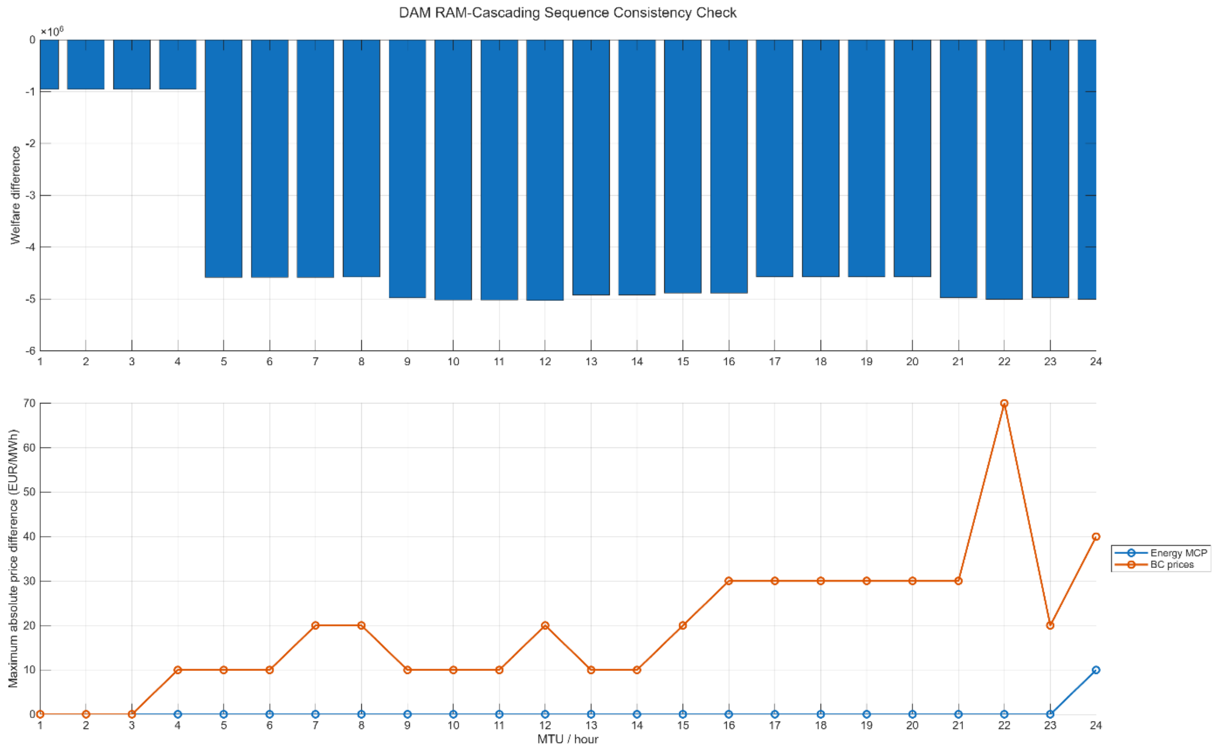


Figure 59. MTU-level diagnostics for the DAM-stage inconsistency of G0a compared with C0a: hourly welfare difference (top) and maximum absolute energy and balancing-capacity price difference (bottom).

3.7.4.14 DAM combined sequential (I0c/DAM vs C0a)

This comparison checks whether the initial DAM stage of the combined sequential scenario I0c reproduces the corresponding standalone co-optimised DAM scenario C0a. Scenario I0c subsequently transfers both unaccepted bids and residual RAM between successive auction stages. Neither mechanism should affect the first DAM clearing, because no preceding auction result is available at that point. The DAM output of I0c and C0a are therefore expected to use the same market inputs, SLR-based flow-based domain and co-optimised clearing formulation.

The reported HU03-KPI2 values are 0.00% for energy, downward aFRR, downward mFRR, upward aFRR and upward mFRR. Downward and upward RR are reported as not applicable because valid relative price-difference values were not available. HU03-KPI3 reports a welfare difference of 0.00%, while the welfare-based beneficial-hours ratio is 0.00%.

These results confirm that the DAM output of I0c reproduces the standalone C0a result at the level of the reported price and welfare indicators. The combined sequential workflow therefore begins from a market outcome consistent with the standalone co-optimised DAM reference. The changes subsequently observed in the IDA stages of I0c can consequently be associated with the transfer of residual bids and residual RAM rather than with a difference already present in the initial DAM clearing.

The zero beneficial-hours ratio does not indicate an unfavourable outcome in this consistency comparison. Since the target and baseline welfare results are identical, no market time unit has a strictly positive difference. Exact equality is the expected and desirable result.

The consistency result also agrees with the bid-forwarding-only sequence examined in Section 3.7.4.12. The DAM-stage KPI files generated for the bid-forwarding and combined sequential workflows were found to be identical, confirming that adding RAM cascading does not alter the initial DAM output before any residual capacity is transferred.

3.7.5 Overall Evaluation

Figure 60 consolidates the product-level HU03-KPI2 results across the applicable comparisons. It highlights three main patterns: co-optimisation primarily changes balancing-capacity price indicators; the alternative bid-source and bid-forwarding configurations produce large negative relative changes in the downward products; and RAM cascading alone produces comparatively small IDA2 price effects. The values remain unweighted relative indicators, and unavailable RR results are shown as not applicable.

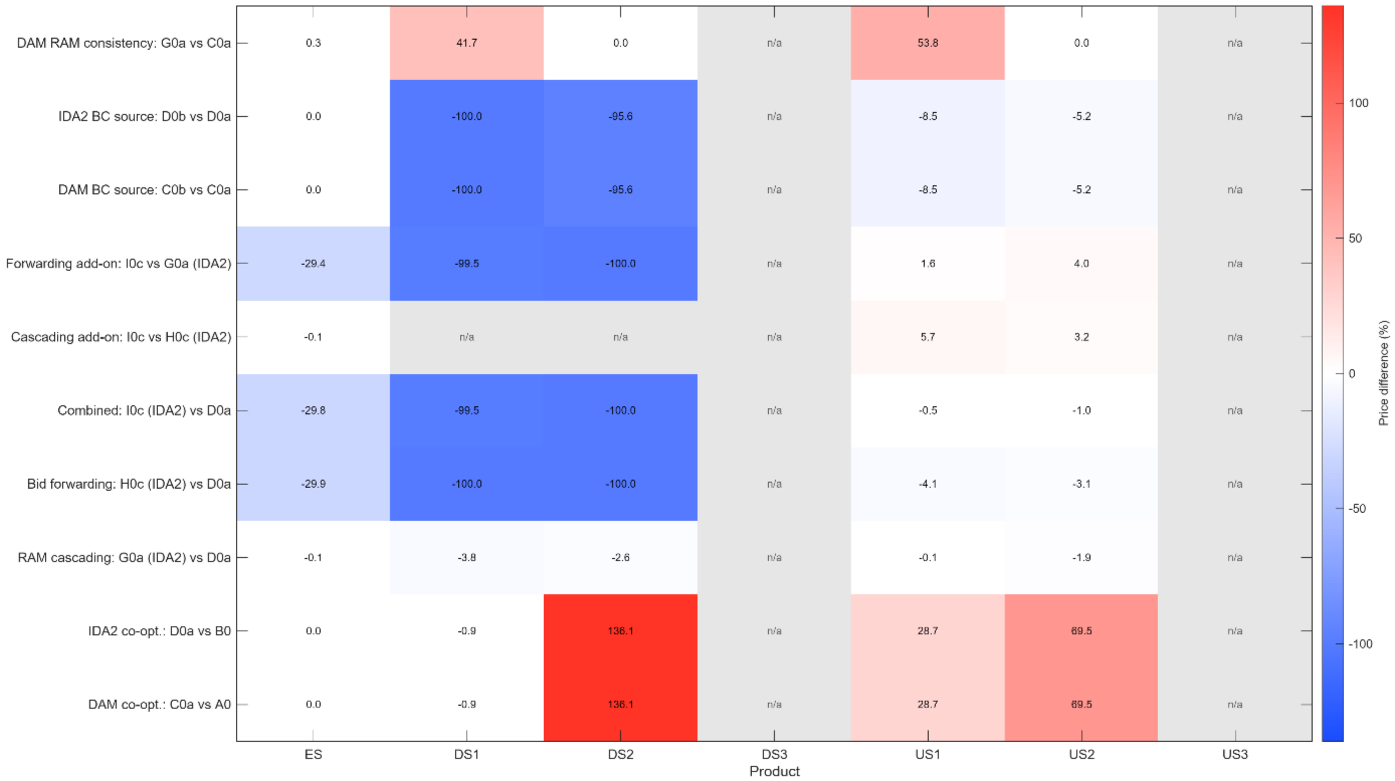


Figure 60. Cross-scenario overview of HU03-KPI2 mean relative price differences by product.

The standalone co-optimisation comparisons produced positive but modest aggregate welfare changes of 0.02% in DAM and 0.05% in IDA2. In both market stages, the energy-price indicator remained unchanged relative to the corresponding non-co-optimised reference, while the more pronounced effects occurred in the balancing-capacity products.

The DLR-enhanced scenarios produced clear changes in the represented capacity domain, with reported aggregate additional RAM values of 781,044 MW in DAM and 736,568 MW in IDA2. However, fewer than 1% of the evaluated CNECs were classified as beneficial, and no measurable welfare improvement was obtained at the available reporting precision. Additional capacity therefore affected only a limited subset of constraints and did not materially alter the market-clearing solution for the evaluated day.

Table 17. Summary of scenario comparison results.

Comparison	Main capacity or price result	Welfare change	Beneficial ratio
C0a vs A0 – DAM co-optimisation	ES: 0.00%; DS1: −0.92%; DS2: +136.11%; US1: +28.70%; US2: +69.52%	+0.02%	37.50% of MTUs
D0a vs B0 – IDA2 co-optimisation	ES: 0.00%; DS1: −0.92%; DS2: +136.11%; US1: +28.70%; US2: +69.52%	+0.05%	37.50% of MTUs
C2a vs C0a – DAM DLR effect	781,044 MW total additional RAM across CNEC–MTU records	0.00%	0.75% of CNECs
D2a vs D0a – IDA2 DLR effect	736,568 MW total additional RAM across CNEC–MTU records	0.00%	0.98% of CNECs
C0b vs C0a – DAM BC bid source*	ES: 0.00%; DS1: −100.00%; DS2: −95.56%; US1: −8.54%; US2: −5.21%	−7.11%	0.00% of MTUs
D0b vs D0a – IDA2 BC bid source*	ES: 0.00%; DS1: −100.00%; DS2: −95.56%; US1: −8.54%; US2: −5.21%	−18.13%	0.00% of MTUs
IDA2 output of H0c vs D0a – bid forwarding**	ES: −29.87%; DS1: −100.00%; DS2: −100.00%; US1: −4.10%; US2: −3.13%	+0.16%	100.00% of MTUs
IDA2 output of G0a vs D0a – RAM cascading**	ES: −0.11%; DS1: −3.76%; DS2: −2.55%; US1: −0.06%; US2: −1.86%	0.00%	4.17% of MTUs
IDA2 output of I0c vs D0a – combined sequence	ES: −29.79%; DS1: −99.50%; DS2: −100.00%; US1: −0.50%; US2: −0.98%	+0.15%	100.00% of MTUs
IDA2 output of I0c vs H0c – RAM-cascading add-on*	ES: −0.09%; US1: +5.75%; US2: +3.19%	−0.0052%	29.17% of MTUs
IDA2 output of I0c vs G0a – bid-forwarding add-on*	ES: −29.44%; DS1: −99.49%; DS2: −100.00%; US1: +1.62%; US2: +4.05%	+0.503%	100.00% of MTUs

* Derived indicators were calculated from the processed target and baseline outputs using the applicable KPI definitions rather than taken from a dedicated official pairwise KPI file. ** Comparisons involving G0a are subject to the DAM-stage consistency limitation described in Section 3.7.4.13

The balancing-capacity bid-source comparisons demonstrate substantial sensitivity to the input dataset. The ENTSO-E-derived input resulted in welfare reductions of 7.11% in DAM and 18.13% in IDA2 despite lower balancing-capacity price indicators. These results should be interpreted as input-data sensitivity findings rather than as a general comparison of the quality of the two data sources.

Among the sequential mechanisms, bid forwarding produced the clearest positive effect. The bid-forwarding-only H0c scenario increased IDA2 welfare by 0.16%, while the combined I0c scenario produced a similar increase of 0.15%; all evaluated MTUs were beneficial in both cases. Adding RAM cascading to the bid-forwarding sequence changed welfare by only −0.0052%, indicating that residual-order liquidity was the dominant contributor to the combined result. Comparisons using G0a remain subject to the unresolved DAM-stage consistency limitation identified in Section 3.7.4.13.

Overall, the simulation confirms the technical execution of the principal demonstration mechanisms and provides directional evidence of their effects. The conclusions remain specific to the evaluated delivery day and should not be interpreted as representative annual or long-term market impacts.

4 Conclusions and Future Perspectives

4.1 Greek Demo Conclusions and Policy Recommendations

Deliverable 7.2 demonstrates that digital twinning in the balancing context can evolve from a descriptive representation of the electricity system into a practical environment for testing market rules, validating schedules and preparing coordinated system operation. The Greek Demo links four distinct functions—day-ahead market simulation, balancing-market optimisation, transmission-grid assessment and distribution-grid prequalification—into a common decision chain. Its policy relevance follows directly from that integration: market efficiency, reserve sufficiency and DER participation are evaluated together with the physical constraints that ultimately determine whether the resulting schedule can be delivered.

The evidence supports neither an unqualified replacement of conventional generation by DERs nor a simple expansion of existing balancing markets. It supports a more disciplined transformation: flexible resources should gain broader access, but their capacity must be traceable, their location must be known, their service stacking must be physically consistent, and their activation must be validated across transmission and distribution levels.

4.1.1 Key Findings from the Greek Demo

- **The market-simulation foundation is sufficiently accurate for scenario analysis.** The DAM Simulator reproduces historical Greek clearing prices with low errors across four contrasting seasonal days. This validated baseline gives credibility to the projected 2030 findings and establishes that the observed welfare and DER-participation changes arise from explicit scenario assumptions rather than from an uncalibrated market representation.
- **The 2030 configuration materially increases both DER market access and social welfare.** Cleared DER transactions increase by approximately 49–77 GWh across the representative days, while total social welfare rises by 22.11%–27.37%. The gains are observed in all seasonal regimes and are driven primarily by increased consumer surplus. However, lower average prices coexist with stronger price variability during high-RES periods, confirming that flexibility must address both cost and volatility.
- **Distributed flexibility can substitute conventional reserve provision under controlled conditions.**
  The 17 May comparison provides the strongest causal evidence: 5.354 GWh of time-aggregated FCR, aFRR and mFRR provision shifts from natural-gas and hydro units to BESS and demand response. Conventional generation, commitment and gas-unit ramping all decline. The result demonstrates that DERs can relieve both the energy and reserve burden of the conventional fleet when common requirements are held constant.
- **Storage value cannot be inferred from energy throughput alone.** The simulations identify energy-cycling, hybrid and headroom-dominated battery regimes. On some days, storage shifts substantial energy; on others, it provides several layers of reserve and congestion support with almost no cycling. Future market and regulatory assessments must therefore value availability, power headroom, directionality and response speed alongside activated energy.
- **Natural gas and hydropower remain essential, but their roles become increasingly specialised.**
  Natural gas remains central to synchronous and downward security, including FCR, aFRR

Down and TSO-CM Down. Hydropower provides upward flexibility substantially above its share of energy production, particularly through mFRR Up and TSO-CM Up. BESS and demand response complement rather than simply replace these resources, allowing each technology to be used closer to its comparative operational strength.

- **Grid validation is the decisive bridge between market access and operational trust.** At transmission level, additional BESS deployment removes an identified Cretan line congestion under the same load and RES conditions. At distribution level, significant battery activation remains within voltage, line-loading, transformer-loading and state-of-charge limits without curtailment. These results demonstrate that DER participation becomes credible when economic clearing is accompanied by explicit locational validation.

4.1.2 Implications for Balancing Market Regulation

The Greek Demo supports technology-neutral access combined with capability-specific qualification. Flexible resources should be allowed to compete with conventional balancing-service providers when they can satisfy the response time, duration, metering, controllability and availability requirements of the relevant product. Technology neutrality should not imply identical treatment: batteries, demand response, hydropower and thermal units expose different physical constraints and therefore require different prequalification evidence.

The results also support the continued development of market products that are compatible with the physical characteristics of emerging resources. In the DAM assessment, storage is represented through charging and discharging orders, while demand response uses flexible block products. Their introduction contributes to substantially higher DER transaction volumes and social welfare. Regulation should therefore avoid forcing storage and flexible demand into bidding structures designed exclusively for conventional generation.

A second implication concerns the distinction between energy activation and capacity value. The 6 July and 21 January cases show that batteries can provide large reserve and congestion-management volumes with minimal energy throughput. A remuneration framework based only on activated energy would fail to recognise the value of maintaining fast, bidirectional headroom. Market design should separately value capacity availability, activation performance and energy delivery.

Third, the market must establish robust rules for service stacking and capacity exclusivity. The same megawatt cannot be sold independently to balancing energy, mFRR, congestion management and FFR if the underlying operating point cannot support all commitments simultaneously. Prequalification and clearing rules should require that accepted services remain within a common resource envelope reflecting generation headroom, storage power, state of charge, demand baseline and connection-level restrictions.

Fourth, distribution-connected flexibility requires locational validation rather than blanket eligibility. The DSO should not determine market prices, but it must be able to confirm, condition or reject an activation where local voltage or equipment limits would be violated. The Greek Demo's DSO workflow—accept, curtail or reject, followed by structured feedback—provides a practical basis for such a role. The TSO should receive only the flexibility that remains technically deliverable after local constraints have been considered.

Fifth, the treatment of fixed pumping schedules illustrates the need for clear regulation of pre-contracted or exogenously determined service contributions. Such quantities should be credited before residual procurement, preventing double payment and double procurement. Any fixed overcoverage should be reported explicitly rather than hidden within an optimised total. The same principle may apply to mandatory reserves, bilateral redispatch, system-protection schemes or other non-market operational actions.

Sixth, daily technology-diversification targets are insufficient on their own. The observed interval-level concentration shows that apparently diversified daily procurement may still depend heavily on a single provider during critical periods. Market monitoring should therefore include the minimum number of active providers, maximum provider share by Market Time Unit, locational concentration and correlated portfolio ownership—not only daily technology shares.

Seventh, the results underline the importance of rigorous counterfactual design in regulatory pilots. Only the 17 May scenario pair isolates the effect of the full flexibility portfolio. Where reserve requirements, imbalance profiles or reduced-case resource eligibility differ, the results describe different configurations but cannot be interpreted as a direct causal effect. Future regulatory impact assessments should preserve identical common requirements and change only the market rule or resource class under examination.

Finally, prospective FFR procurement should proceed through targeted pilot arrangements. The model demonstrates the potential value of fast battery-based response under high-RES conditions, but the requirement remains a planning proxy. Formal market introduction would require dynamic frequency studies, product-duration definitions, prequalification standards, activation logic and settlement provisions.

4.1.3 Recommendations for Scalable TSO–DSO Coordination

1. Establish a shared flexibility and asset registry. The TSO, DSO and market operator should use a common identity for each resource or aggregate. At minimum, the registry should include connection point, connection level, technology, aggregator, power and energy limits, eligible services, response time, prequalification status and current availability. The Greek Pilot Asset Registry already provides the conceptual foundation for this approach.

2. Separate static prequalification from dynamic network validation. Static prequalification should establish whether a resource is technically capable of providing a product. Dynamic validation should determine whether it can provide that product at a specific time and location without violating the current network state. This distinction allows market access to remain open while preserving the DSO's ability to protect local voltage and loading limits.

3. Apply a local-security-first, residual-flexibility principle. Distribution-grid security must remain binding. Once local DSO needs and restrictions are satisfied, the residual feasible flexibility should become available for TSO balancing and system services. This does not require the DSO to participate in price formation; it requires the DSO to expose a technically validated flexibility envelope.

4. Develop a machine-readable market–grid feedback loop. The current exchange of schedules and validation reports should evolve from manual or semi-automated files toward standardised APIs and version-controlled schemas. A rejected schedule should be accompanied by an actionable constraint: affected asset or node, direction, relevant periods and maximum admissible activation. The BM Digital Twin can then re-optimise against that constraint rather than rely on manual interpretation.

5. Define explicit conflict-resolution rules. The same resource may face simultaneous TSO and DSO requests or conflicting upward and downward activations. Coordination rules should define the precedence of local emergency actions, pre-contracted services, accepted balancing bids and residual availability. Every change in availability should be time-stamped and visible to both operators.

6. Coordinate procurement without erasing institutional responsibilities. A scalable model does not require one monolithic TSO–DSO optimisation platform. The Greek Demo shows the value of maintaining specialised modules: market clearing, balancing optimisation, TSO validation and DSO validation. Scalability depends on interoperable interfaces and clear decision rights, not on centralising every calculation within one organisation.

7. Introduce common operational and concentration KPIs. Coordination should be evaluated through more than total cost. Recommended indicators include grid-feasible DER volume, avoided redispatch, number of rejected or curtailed activations, reserve sufficiency, maximum provider concentration, storage headroom use, convergence time of the validation loop and the volume of flexibility remaining available after local validation.

The key lesson is that successful coordination should make local constraints visible early enough to influence clearing—without converting the DSO into a market operator or depriving the TSO of access to technically feasible distributed flexibility.

4.1.4 Digital Twin Replicability for Other Regions

The Greek framework is replicable because it is modular by design. Its transferable architecture comprises a scenario-based DAM Simulator, a balancing-market optimiser, a reserve and imbalance calculation layer, a transmission-grid validation tool and a distribution-grid prequalification tool. Each module can be adapted independently while retaining the same overall logic: generate market schedules, determine balancing needs, co-optimise flexibility, validate the network and revise the schedule where necessary.

Replication should be understood as methodological portability rather than immediate plug-and-play deployment. Another region would need to replace the Greek market rules, asset mappings, reserve products, network representations and institutional responsibilities with its own. The core workflow, however, remains applicable.

A minimum replication dataset should include:

- time-aligned demand and RES profiles;
- market schedules or representative orderbooks;
- system imbalances and reserve requirements;
- unit and DER technical characteristics;
- balancing-energy and reserve offers;
- resource-to-system and resource-to-connection-point mappings;
- transmission and distribution validation limits;
- common identifiers and sign conventions.

The framework can support several levels of data maturity. A first deployment may use zonal market models and transparent congestion proxies. A more advanced implementation may retain separate market and grid tools but exchange explicit asset or nodal limits. A high-fidelity deployment may introduce PTDFs, contingency constraints, distribution sensitivity factors, feeder limits and voltage constraints directly into the optimisation or into a tightly coupled iterative validation process.

The Greek Demo also demonstrates a practical approach to confidentiality. Market assets can be pseudonymised, network topology can be anonymised, and the grid tools can return only the constraint information required for re-optimisation. Replication therefore does not require uncontrolled disclosure of commercially sensitive bids, customer-level information or complete critical-infrastructure models.

Interoperability remains a central dependency. The current use of structured spreadsheets, CSV and JSON supports transparency and testing, but scaling to routine multi-operator use will require formal APIs, schema governance, automated validation, access controls and cyber-secure exchange. The data model should preserve a common 15-minute time base while allowing individual tools to use different internal representations.

Regulatory differences will often be more significant than technical differences. Other countries may assign different responsibilities to DSOs, use different reserve products, apply portfolio rather than unit-based bidding, or have different rules for independent aggregation and redispatch. The digital twin should therefore treat service eligibility, prequalification, bid structures and operator rights as configurable parameters rather than hard-coded assumptions.

The most transferable output of the Greek Demo is consequently not a single GAMS, Python, Julia, PSS®E or PowerFactory implementation. It is a disciplined replication pattern: validate the market model, preserve the physical source of flexibility, separate global and local requirements, exchange constraints through traceable interfaces, and reject any schedule that fails the final grid-feasibility test.

4.2 Hungarian Demo Conclusions

Task 7.3 established an integrated and reproducible demonstration workflow linking energy-market data, balancing-capacity procurement, flow-based transmission-capacity calculation, DLR-based capacity adjustments, co-optimised market clearing and quantitative scenario evaluation. The resulting environment reproduces the technically relevant sequence and information exchanges of European day-ahead and intraday market coupling in a controlled parallel dry run. Its principal contribution is therefore not a replacement for the operational SDAC and SIDC processes, but an integrated framework in which alternative market and capacity-calculation arrangements can be evaluated consistently without creating physical, financial or legal consequences.

The demonstration also increased the operational relevance of the earlier FARCROSS prototype. The market-clearing and capacity-calculation components were integrated with real or operationally representative datasets, market-product definitions, flow-based constraints and auction sequences. HUPX Labs, an existing proprietary platform used in an industrial NEMO environment, was employed for data exchange, result storage and visualisation; it was not developed within TwinEU. The project-specific contribution lies in integrating the capacity-calculation, market-clearing, scenario-management and result-processing components around this existing platform. This integration demonstrates that the proposed functions can be implemented using market-compatible data structures and workflows rather than being limited to an isolated mathematical model.

The simulation results confirm that the co-optimised clearing approach can be executed for both the day-ahead market and the evaluated IDA2 intraday auction. Compared with the respective separated-market reference cases, co-optimisation produced positive but modest welfare changes of

0.02% in the day-ahead market and 0.05% in IDA2. In both comparisons, 37.50% of the evaluated market time units were classified as beneficial. The energy-price indicator remained unchanged, while the more visible effects occurred in balancing-capacity price formation. These results show that the economic effect of co-optimisation cannot be assessed from wholesale energy prices alone. Accepted balancing-capacity quantities, product-specific prices, procurement costs and the interaction between energy and reserve allocation must also be considered.

The DLR-enhanced cases demonstrated a clear effect on the represented flow-based capacity domain. The reported additional RAM amounted to 781,044 MW across the evaluated DAM CNEC–MTU records and 736,568 MW across the corresponding IDA2 records. These totals are cumulative values across multiple network constraints and market time units and must not be interpreted as simultaneously available cross-zonal capacity. Fewer than 1% of the evaluated CNECs were classified as beneficial, and no measurable welfare improvement was obtained at the available reporting precision. The principal conclusion is therefore that additional technical capacity does not automatically generate an economic benefit. DLR affects market outcomes only where the modified constraints are binding, or sufficiently close to binding, in the welfare-maximising solution. Future evaluation should consequently connect DLR-adjusted RAM directly to constraint utilisation, shadow prices, accepted volumes and congestion patterns rather than relying on aggregate additional RAM alone.

The sequential scenarios provided a further important result. Bid forwarding produced the clearest positive effect among the evaluated mechanisms: the IDA2 output of the bid-forwarding sequence increased welfare by 0.16% relative to the standalone IDA2 case, and all evaluated market time units were beneficial. The combined bid-forwarding and RAM-cascading sequence produced a similar welfare increase of 0.15%, again with all market time units classified as beneficial. By contrast, adding RAM cascading to an already active bid-forwarding sequence changed aggregate welfare by only −0.0052%. For the evaluated delivery day, residual-order liquidity was therefore the dominant contributor to the combined sequential result, while the incremental economic effect of residual-RAM transfer was marginal.

The RAM-cascading-only results cannot yet be treated as a fully isolated assessment of that mechanism. The initial DAM stage of the G0a sequence did not reproduce the corresponding standalone co-optimised DAM result, even though RAM cascading should not affect the first auction. The discrepancy may originate from scenario initialisation, input transformation, network-data preparation or another preprocessing difference, but its precise cause cannot be identified from the available outputs. Consequently, comparisons involving G0a remain indicative. This does not invalidate the demonstrated ability to execute a sequential capacity-update workflow, but it prevents a definitive quantitative conclusion on the economic value of RAM cascading until the initial-stage inconsistency is resolved.

The balancing-capacity bid-source comparisons showed that model outcomes are highly sensitive to input-data representation. Replacing the HUPX Labs/MAVIR dataset with the ENTSO-E-derived input resulted in welfare reductions of 7.11% in DAM and 18.13% in IDA2, despite decreases in several balancing-capacity price indicators. These findings do not establish that either data source is generally superior. Instead, they demonstrate that source coverage, bid-curve reconstruction, linearisation, offered quantities and preprocessing assumptions can have a greater influence on the calculated outcome than some of the investigated market-design changes. Transparent data provenance and harmonised preprocessing are therefore prerequisites for credible cross-scenario evaluation.

More generally, the implementation confirmed that data integration remains one of the principal barriers to developing and validating interconnected European electricity-market digital twins. Relevant inputs were obtained from HUPX, MAVIR, JAO, the ENTSO-E Transparency Platform, NEMO sources and partner-internal systems, with differing formats, temporal resolutions, identifiers, time-zone conventions and access conditions. Confidentiality obligations also limited the distribution of some operational datasets. The practical value of standardised, technology-agnostic interfaces is therefore not only improved software interoperability, but also reproducible data selection, controlled versioning and traceable transformation of market and network inputs.

The quantitative findings remain subject to the limitations of the evaluated simulation batch. The assessment covers one delivery day and is therefore suitable for demonstrating workflow functionality, scenario consistency and directional market effects, but not for estimating annual welfare impacts or long-term congestion benefits. Some scenarios were not executed, the IDA3 stage could not be completed where the required PTDF data were unavailable, and the DLR-enhanced forecast horizon was restricted by the available 24-hour meteorological forecast. In addition, unstable CNEC identifiers prevented consistent accumulation of network-element results across market time units. Several price indicators are unweighted relative measures and should not be interpreted as direct changes in total procurement expenditure.

Further validation should therefore prioritise the execution of the scenario matrix over a wider range of delivery days and system conditions, completion of the missing intraday stages, stable identification of physical CNECs across timeframes, and resolution of the G0a initial-stage discrepancy. Price indicators should be evaluated together with accepted quantities, procurement expenditure, shadow prices and binding-constraint information. These steps would allow the demonstrated technical functions to be separated more clearly from data-specific or preprocessing effects.

Overall, Task 7.3 demonstrates that DLR-enhanced flow-based capacity calculation, energy and balancing-capacity co-optimisation, and sequential auction mechanisms can be integrated into a common, operationally relevant simulation workflow. The results provide evidence of technical feasibility and identify where potential market benefits may arise, particularly through co-optimised balancing-capacity allocation and the forwarding of residual bids. At the same time, they show that the magnitude of these benefits is strongly dependent on congestion conditions, market liquidity and input-data quality. The demonstration therefore provides a credible basis for scientific dissemination, knowledge transfer and potential future uptake, while further operational deployment would require broader validation, stable data governance, formal operational responsibilities and integration with the legally binding confirmation, nomination, clearing and settlement processes that remain outside the scope of TwinEU.

4.3 Integrated Cross-Demonstration Synthesis

4.3.1 Complementary Contributions of the Two Demonstrations

The Greek and Hungarian demonstrations address different but mutually reinforcing dimensions of digitalised electricity-system operation. The Greek pilot examines whether market-cleared flexibility can meet balancing requirements and remain feasible within transmission and distribution networks. The Hungarian pilot examines whether short-term energy, balancing capacity, and cross-zonal network capability can be coordinated across successive auctions. The combined evidence therefore spans the chain from resource-level flexibility and local deliverability to regional capacity allocation and coupled-market efficiency.

Both pilots confirm the value of modularity. Specialised tools can retain their institutional and technical functions while exchanging only the information needed by the next stage. This is more scalable than attempting to reproduce every market, grid, and forecasting function in one monolithic model.

4.3.2 Market Efficiency and Flexibility Utilisation

The results show that co-ordination creates value through two distinct mechanisms. In Greece, additional DER participation enlarges the feasible balancing portfolio, reduces conventional reserve provision in a controlled counterfactual, improves welfare, and can resolve network constraints when resources are correctly located. In Hungary, co-optimisation reallocates energy and balancing capacity within a common welfare objective and produces positive, although comparatively modest, welfare gains in the evaluated DAM and IDA2 cases.

The contrast is instructive. Large economic effects arise where the underlying system composition and resource portfolio are materially transformed, as in the Greek 2030 scenarios. Smaller percentage gains can still be operationally relevant where a mature coupled market is refined through co-optimisation, as in the Hungarian cases. In both settings, the distribution of benefits across products and intervals is more informative than a single daily welfare value.

4.3.3 Grid Capability, Congestion, and Dynamic Capacity

The Greek network studies demonstrate that the location and direction of flexibility determine whether a market schedule is deliverable. The Hungarian DLR studies demonstrate that the admissible transfer capability of the grid is itself dynamic and can be increased or reduced by environmental and thermal conditions. Together, these findings show that market efficiency depends on two-way interaction: markets must respect the current network envelope, while network models should expose updated capacity as accurately and promptly as possible.

The integrated TSO–DSO congestion-management methodology and the flow-based DLR workflow address the same underlying risk from different perspectives: static or independently calculated limits may either duplicate procurement or leave usable capacity inaccessible. Conservative consolidation and validated dynamic ratings can improve utilisation without weakening security requirements.

4.3.4 Interoperability, Data Governance, and Validation

Data quality is a first-order modelling assumption rather than an administrative detail. The Greek pilot required consistent asset mappings, sign conventions, service definitions, and time-aligned DAM, ISP, and grid inputs. The Hungarian pilot required harmonisation across HUPX, MAVIR, JAO, ENTSO-E, NEMO, and partner-internal datasets, under substantial confidentiality constraints. The sensitivity of Hungarian welfare results to the balancing-capacity bid source illustrates how strongly data provenance can affect model outcomes.

A scalable digital twin therefore requires governed schemas, versioned datasets, common identifiers, automated quality checks, and explicit fallback rules. Validation must cover both numerical closure and physical meaning: energy and reserve balances, resource capability, provider concentration, network violations, and consistency between sequential market stages.

4.3.5 Limitations and Interpretation Boundaries

The demonstrations are deterministic and scenario based. The Greek balancing model uses aggregated congestion requirements rather than a complete nodal AC formulation, while the Hungarian DLR forecast horizon is limited by the availability of weather and load forecasts. Some interfaces remain manual or semi-automated, and several Hungarian sequential scenarios could not be completed because the necessary stage-specific data were unavailable.

These limitations do not invalidate the results, but they define the appropriate claims. Controlled comparisons are distinguished from configuration-level comparisons; reconstructed public datasets are distinguished from confidential operational order books; and planning proxies are distinguished from full dynamic security assessments.

4.4 Integrated Recommendations and Future Perspectives

4.4.1 Overall Findings

The integrated demonstrations establish that digital twins can serve as operationally relevant test environments for electricity-market transformation. They can connect market schedules, balancing and capacity requirements, resource constraints, network capability, and validation outputs in a form that is repeatable and auditable.

The principal findings are: (i) distributed flexibility can materially improve welfare and reduce conventional balancing burdens when it is technically and locationally deliverable; (ii) co-optimised energy and balancing-capacity clearing can improve welfare and price outcomes, although the magnitude depends on market conditions and input data; (iii) DLR can expose substantial additional network margin on selected critical elements; (iv) local grid validation and cross-zonal capacity calculation are complementary prerequisites for efficient flexibility use; and (v) data governance and interface quality are as important as the optimisation algorithms themselves.

4.4.2 Regulatory and Market-Design Implications

Market access should be technology neutral but capability specific. Batteries, demand response, aggregated prosumers, conventional units, and hydro resources should compete where they can satisfy the response, duration, metering, and deliverability requirements of the relevant product. The same physical capability must not be sold simultaneously to incompatible energy, reserve, congestion-management, or cross-zonal capacity obligations.

The Greek results support explicit DSO validation of distribution-connected flexibility and transparent treatment of fixed or pre-contracted service contributions before residual procurement. The Hungarian results support continued regulatory and operational testing of co-optimised cross-zonal capacity allocation, bid forwarding, RAM cascading, and DLR-enhanced capacity calculation. Regulatory pilots should preserve controlled baselines and publish sufficient methodological information to distinguish genuine market-design effects from input-data effects.

4.4.3 Recommendations for Scalable Coordination and Co-Optimisation

A scalable implementation should establish a common resource and network-data registry, dynamic availability validation, machine-readable constraint feedback, and a single conflict-resolution chain for overlapping market and system-operator requests. Local network security must remain binding, while residual feasible flexibility should be exposed to wider system and market use.

Sequential market processes require equally disciplined state transfer. Accepted bids, residual bids, net positions, allocated cross-zonal capacity, and updated RAM must be carried between auctions using consistent identifiers and time stamps. The interfaces should be API based, cyber-secure, version controlled, and capable of reporting the reason for any rejected or modified schedule.

4.4.4 Digital-Twin Replicability and Exploitation

The combined toolchain is replicable because it is modular. Another region can replace the Greek or Hungarian market rules, reserve products, asset mappings, network models, and institutional roles while retaining the same workflow of scenario generation, optimisation, validation, and KPI assessment. Replication should proceed in tiers, from transparent zonal proxies to explicit PTDF, contingency, feeder, voltage, and dynamic-frequency models as data maturity increases.

The most transferable assets are the data dictionaries, mapping and validation routines, scenario matrices, interface schemas, controlled comparison rules, and operator-oriented KPIs. These elements should be packaged together with anonymised benchmark datasets so that replication evaluates the method rather than merely reusing software code.

4.4.5 Next Steps in TwinEU WP7 and WP9

The immediate priority is to consolidate a canonical integrated reference version of the Greek and Hungarian workflows, including approved input mappings, scenario definitions, model versions, and automated audits. The remaining Hungarian scenarios should be completed where the necessary PTDF and auction-stage data become available, and the Greek counterfactual design should be harmonised across all representative days.

Further development should automate the market–grid feedback loops, introduce explicit storage state-of-charge and demand-response recovery trajectories, extend transmission and distribution validation across more periods and contingencies, and incorporate forecast uncertainty through stochastic or robust formulations. DLR forecasting should be extended beyond the current horizon where data permit.

The integrated evidence should feed directly into WP9 replication and impact assessment, supported by structured engagement with TSOs, DSOs, NEMOs, regulators, aggregators, and technology providers. The long-term TwinEU legacy should be a reusable European decision-support capability in which new market products, capacity-calculation methods, and coordination arrangements can be tested economically, validated physically, and refined transparently before deployment.

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