Utilities Policy 100 (2026) 102172

Contents lists available at ScienceDirect

Utilities Policy

journal homepage: www.elsevier.com/locate/jup

Full-length article

# Efficiency and market power analysis of alternative reserve market design proposals: a case study of Greece

Anthony Papavasiliou [a,b,*], Daniel Ávila [b]

[a] National Technical University of Athens, Greece
[b] Arktos Analytics, Belgium

ARTICLE INFO

Handling Editor: Janice A. Beecher

*Keywords:*
Co-optimization
Reserves
Balancing capacity
Market power

ABSTRACT

The Greek day-ahead electricity market is currently organized as a sequential clearing of energy followed by a clearing of reserves through a unit-based integrated scheduling process. Inspired by the design of Central and Western Europe, a recent proposal by the Hellenic Transmission System Operator favors transition to a portfolio-based pay-as-bid pricing design where the clearing of the day-ahead reserve market is moved before the clearing of the day-ahead energy market. We discuss the motivations for the proposed redesign and follow a three-pronged approach for analyzing the proposal. Firstly, using a production simulation model of the Greek system, we benchmark the efficiency of the proposal against an idealized design where energy and reserves are co-optimized at the stage of day-ahead market clearing. Secondly, we propose a dominant firm model for analyzing market power in energy and reserves markets and derive analytical insights that can contribute to the ongoing policy debate. Finally, we discuss the current state of affairs in the Greek day-ahead market for reserves. The analysis uncovers significant potential efficiency losses (in the range of 6.6-6.9%, barring intraday and real-time corrections within portfolios) resulting from sequential clearing relative to an idealized co-optimization benchmark as well as concerns about enabling the exercise of market power in the energy and reserves market under either sequential or co-optimized clearing when market concentration is an issue.

## 1. Context

Despite its move towards integration, the common European electricity market still features notable heterogeneity with respect to the trading of reserves, or balancing capacity, as it is referred to in Europe. Most effort and progress in the past years have been dedicated towards the integration of the European day-ahead energy market, referred to as Single Day-Ahead Coupling (SDAC). The integration of continuous intraday markets is also well underway through the so-called XBID platform. The integration of real-time energy markets, or balancing energy markets as they are referred to in Europe, is spearheaded by the deployment of the PICASSO cross-border platform for the activation of automatic frequency restoration reserves (aFRR) and the MARI cross-border platform for the activation of manual frequency restoration reserves (mFRR). By contrast, although there has been an effort to harmonize the definition of reserve products in Europe in order to enable cross-border sharing and exchange of such products, European markets for reserve remain fragmented. The fact that SDAC clears energy only in the day ahead precludes the co-optimization of energy and reserves for the time being, thus certain European systems rely on clearing reserves before energy while others clear reserves after energy. We discuss the details of the European market for reserves in section 2.1. At this stage of setting the context, it suffices to keep in mind that Central Europe follows a design whereby reserves are cleared before the day-ahead energy market, whereas in Greece, which is the focal point of the present work, reserves are cleared after the day-ahead energy market.

In the meanwhile, the entire continent is advancing steadily towards achieving highly aggressive goals in terms of integrating renewable energy resources. There are signs that the system is moving into unchartered territory in terms of its ability to securely absorb renewable resources: the number of days during which renewable supply was curtailed in Greece rocketed from 7 in 2022 to 43 in 2023 to 192 in 2024. As a further symptom of the inability of the system to absorb oversupply, in certain European countries, especially the Nordics, zero or negative electricity prices occur approximately 10% of the time. In this respect, flexibility in the form of reserves and the ability of system operators to coordinate the provision of reserves with the provision of

---

* Corresponding author. National Technical University of Athens, Greece
*E-mail address:* papavasiliou@mail.ntua.gr (A. Papavasiliou).

https://doi.org/10.1016/j.jup.2026.102172
Received 15 August 2025; Received in revised form 19 February 2026; Accepted 22 February 2026

energy is becoming an increasingly important consideration.

The Greek day-ahead market for reserves is currently cleared after the day-ahead energy market. Our focus in this paper is a proposal by the Hellenic Transmission System Operator (Independent Power Transmission Operator, IPTO), which is currently under public consultation0F,[1] to move away from the current design and transition towards the current design of Central Western Europe, whereby reserves are cleared before the day-ahead energy market. We discuss certain concerns with the existing Greek design which may have motivated this proposal, the possible implications of the proposal in terms of economic efficiency relative to an energy-and-reserves co-optimization benchmark, as well as the interplay between alternative market design choices and the possible exercise of market power by a dominant firm. Although the discussion is inspired by the Greek case, the dilemmas that are raised are of broader relevance for the design of reserve markets internationally. The question of co-optimization of energy and reserves is settled in only a handful of markets around the world.

We do not attempt to analyze every facet of the IPTO proposal in this work. Instead, the technical analysis focuses on issues relating to economic efficiency relative to an energy-and-reserves co-optimization benchmark and opportunities for exercising market power. In order to assess the efficiency implications of the proposal of IPTO, we apply a production simulation model (Ávila and Papavasiliou, 2024) that has been developed for the purpose of similar efficiency assessments for the Core region of Europe (which corresponds to roughly 40% of the European continent) to the case of the Greek system. The employed model represents the Greek market as a unit-based1F[2] unit commitment model. Co-optimization is modeled through standard methods that have been used widely in the literature (Morales et al., 2009). The modeling of the proposed sequential design favored by IPTO relies on a clearing of reserves followed by a clearing of energy. In the sequential design, opportunity costs for offering reserves are represented through estimates of energy prices and certain operational decisions that are determined by the reserve market are fixed before advancing to the clearing of the energy market. The model is intended to quantify the efficiency losses of errors in irrevocable short-term scheduling decisions due to the separation of interacting energy and reserve scheduling decisions relative to an energy-and-reserves co-optimization benchmark, without attempting to compare the existing design in Greece to the proposal favored by IPTO. Barring intraday and real-time scheduling corrections, these efficiency losses are estimated at 6.61%-6.92% for the Greek system under a baseline scenario with specific assumptions concerning the management of hydro resources. The results exhibit notable sensitivity to assumptions on the operation of hydro assets, which constitute an important component of the Greek electricity mix. In light of the proposal of IPTO to introduce portfolio-based bidding and pay-as-bid pricing in the clearing of reserve markets, which arguably complicates market power monitoring and mitigation, we further propose an analytical model for analyzing the exercise of market power in joint energy and reserve markets with a dominant firm and fringe competition. Although the analysis is complexified by the joint interaction of energy and reserves, the main intuition of classic market power models remains, and the analysis reveals a significant scope for lifting prices at inefficient levels in both energy and reserve markets. The efficiency losses revealed by the production simulation model combined with the market power concerns stemming from the analytical model therefore raise concerns regarding the proposal to launch a lengthy and laborious effort to uproot the existing reserve market in Greece. Instead, it may be preferable to wait out the evolutions that are taking place at European level for transitioning to a co-optimized clearing of day-ahead energy and reserve by focusing on improving the current implementation of reserve markets in Greece.

The remainder of the paper is organized as follows. In section 2 we describe the existing organization of the European market for reserves and discuss relevant literature on the design of markets for reserves as well as market power analysis. In section 3 we describe the methodology of our analysis, which consists of (i) developing a production simulation model of the Greek electricity market for the purpose of analyzing the possible implications of sequential clearing on economic efficiency, (ii) an analysis of market power in energy and reserve markets and (iii) a discussion of the state of affairs in the Greek electricity market. In section 4 we present our results. In section 5 we discuss our findings and review interpretations and caveats of our analysis. We conclude in section 6.

## 2. Background

We commence by providing a high-level overview of European electricity markets. We then discuss relevant literature on the efficiency analysis of alternative reserve market designs as well as relevant literature on modeling market power in electricity markets.

### 2.1. European markets for reserve

There are four principal reserve products that are traded in continental Europe. In order of increasing quality/decreasing activation time, these are replacement reserve (RR), upward and downward manual frequency restoration reserve (mFRR), upward and downward automatic frequency restoration reserve (aFRR) and frequency containment reserve (FCR). The majority of the European reserve market corresponds to aFRR and mFRR. These reserve products are procured in the day-ahead time frame. Selling these reserves in the day-ahead reserve market is equivalent to selling a promise to the system operator to bid *at least* the cleared reserve capacity into the real-time energy market. For instance, selling 1 MW of mFRR in the day-ahead reserve market implies an obligation to bid at least 1 MW in the MARI platform which is the real-time platform for activating mFRR balancing energy.

The platforms for activating real-time balancing energy (most notably MARI and PICASSO) are moving towards integration in Europe. Operational members on the MARI platform include Spain, Portugal, Germany, Belgium, Czechia, Slovakia, Austria, Estonia, Latvia and Lithuania. Operational members on the PICASSO platform include Spain, France, Italy, Belgium, the Netherlands, Germany, Denmark, Austria, Slovakia, Hungary, Czechia, Greece, Bulgaria, Estonia, Latvia, Lithuania and Finland. This integration allows national transmission system operators to trade balancing energy in real time across borders, following a uniform set of market clearing rules that apply to all Member States that join these platforms. By contrast, there is no common design for day-ahead markets for reserve, i.e. for committing this balancing capacity one day in advance. Since day-ahead energy is already being cleared in isolation within the Single Day-Ahead Coupling (SDAC) platform, Member States currently must choose to either clear reserves before or after SDAC. We discuss the push towards co-optimizing the clearing of energy and reserves within SDAC in section 2.2.

The Core region of Europe, which largely covers Central Europe (and effectively some of its largest and most influential Member States, including Germany and France) follows a design whereby reserves are cleared before the day-ahead energy market. Since there is currently no homogeneous European design for reserves2F,[3] the precise market

---

[1] https://www.raaey.gr/energeia/diavoulefseis/112969/.

[2] We discuss the unit-based assumption in section 5.1, where we review various limitations and caveats of our analysis. Nevertheless, note that this unit-based proxy is standard procedure in similar academic (Farahmand et al., 2012) and industry (Consentec, 2025) studies.

[3] As we discuss in section 5.3, a homogeneous European design for the reserve market is currently being put in place. One interesting aspect of this design is the requirement for uniform pricing in the sharing and exchange of reserve, see article 4.2 of (ACER, 2025a,b).

clearing arrangements vary. For instance (ELIA, 2024; ELIA, 2023), in Belgium both aFRR and mFRR are cleared daily, with aFRR cleared before mFRR. Both reserves are paid as bid. There is portfolio bidding in both markets. Unit-specific schedules are proposed to the transmission system operator (in a process referred to in Europe as *nominations*) after the clearing of both reserves and energy, meaning that the asset owners propose production schedules for their individual assets so that they can meet the obligations implied by their positions in the day-ahead energy and reserve markets. The TSO may ask asset owners to change some of their nominations in order to ensure that production schedules are compatible with other system requirements (e.g. security constraints or transmission network limits) and these changes are typically settled out of the market (commonly in pay-as-bid settlements) with asset owners.

Other systems, such as Greece and Italy, clear reserves after the day-ahead energy market. The Greek design is specifically based on repeated runs of a so-called Integrated Scheduling Process (ISP) after the clearing of the day-ahead energy market and at scheduled times at or before the day of operation, but after the day-ahead energy market clears. Additional unscheduled ISP runs can take place in case of significant unanticipated system disturbances, e.g. contingencies. Note that the European day-ahead energy market clears around 1p.m. ISP runs are based on a unit-based co-optimization model of energy and reserves, where the goal is to satisfy the reserve requirements of the system as well as "imbalances" (in the sense of deviations between TSO load forecasts and commercial demand positions of market participants) at minimum cost while satisfying the detailed technological constraints of individual units. The day-ahead energy trades of individual units serve as input to the ISP runs, since the Greek day-ahead energy market is in fact unit-based. The ISP computes uniform prices of aFRR and mFRR, even if these prices are not actually used for settlement since reserves are currently paid as bid in Greece. Nominations are not required in this setup, since the ISP accounts endogenously for system constraints (including transmission network limits).

An important consideration to keep in mind relates to reserve sharing and exchange. Reserve exchange refers to the practice whereby a system operator can procure its own reserve needs from a neighboring control area through exclusive access to the reserve in question. In reserve sharing, TSOs of neighboring control areas gain non-exclusive access to the same reserves, counting on the fact that the two system operators will not require the same reserves simultaneously. Reserve sharing and exchange already takes place in the Core region of Central Europe, and one of the motivations behind the proposal of the Greek TSO for changing the Greek design is to enable the participation of Greece in reserve sharing and exchange in the Core region. We revisit this point in section 5.3.

From the above discussion, it becomes clear that reserve market designs can differ quite markedly. In this paper we focus concretely on the aspect of the timing of reserve clearing and its effect on short-term operational efficiency, as well as the scope for exercising market power in energy and reserve markets.

### 2.2. *Co-optimization versus sequential clearing of reserves*

Fig. 1 depicts the three alternative reserve designs that the current paper focuses on. The design on the top of the figure, denoted as (Seq), corresponds to the current model that is employed in Central Europe. The middle part of the figure depicts the current Greek design. These two models are discussed in detail in section 2.1. In this section we focus on a third alternative option, which is depicted in the bottom of Fig. 1, and corresponds to the co-optimization of energy and reserves in a one-shot multi-product auction.

Shortly after deregulation, numerous US markets rapidly evolved from a separation of power exchanges and transmission system operators (as was the case, for instance, in the California market before 2001) to joint independent system operations. Co-optimization of energy and reserves is now thus part of the US standard market design, and has been adopted in numerous liberalized markets in the United States since the early 2000s (Liu et al., 2002), although the first international example of electricity market design to feature co-optimization of energy and reserves was New Zealand in 1996 (Read, 2010). An exception to the rule in US markets was California, which followed a more circuitous route towards co-optimization by first experimenting with various failed sequential designs, which led to adverse phenomena including price reversals in reserve markets, an erratic behavior of reserve prices and the disconnect between energy and reserve prices, as documented in (Gomez et al., 1999; Oren, 2001). The rational buyer approach (Liu et al., 2002) was attempted as a remedy to these troubles until co-optimization of energy and reserves was also adopted in California in the Market Redesign and Technology Upgrade (MRTU), see (Wu et al., 2005). Perhaps in part due to this early adoption of co-optimization of energy and reserves in the United States, there appears to be a shortage in the US academic and industry literature of quantitative comparisons of alternative paradigms based on sequential clearing of energy and reserves. Instead, publications focus on detailed aspects of the implementation of co-optimization, see for instance (Zheng & Litvinov, 2008) for a discussion of real-time co-optimization with zonal reserve requirements (Zheng & Litvinov, 2006), for ex-post pricing of energy and reserves and (Gan & Litvinov, 2003) for an analysis of lost opportunity costs in co-optimization.

Europe has yet to follow suit in co-optimizing the clearing of energy and reserves. Thus, interestingly, European literature is more advanced in drawing quantitative comparisons between sequential and simultaneous clearing alternatives. A case study of coordinating balancing in Northern Europe by committing reserves based on a co-optimization of energy and reserve was presented in early work by (Farahmand et al., 2012). The effects of departures from co-optimization on European wind-dominated systems has been studied by (Smeers et al., 2021).

Although Europe continues to operate under a separate clearing of energy and reserves in the day ahead, there is certainly policy momentum for transitioning to co-optimization as part of the coupled European market in the coming years. Article 40 of regulation 2017/2195 on electricity balancing (European Commission, 2017), which concerns the allocation of network capacity between European Member States for exchanging and sharing reserves under a co-optimized design of day-ahead energy and reserves, triggered a series of feasibility studies for the transition to co-optimization in the European day-ahead market. These included assessments of the technological feasibility of modifying the existing algorithm for clearing day-ahead energy in order to accommodate the joint clearing of energy and reserves (N-SIDE AFRY, 2020; N-SIDE, 2022), followed by an implementation impact assessment by ENTSOE that included governance and broader implementation considerations (ENTSO-E, 2021). Work is currently underway within SDAC for taking the original analyses further and developing a better understanding of alternative bidding products, and design and pricing choices (MCSC SDAC, 2025), (ACER, 2025a), (MCSC, 2025).

An assessment of the economic benefits of transitioning from the existing sequential clearing design to a co-optimization design in the European day-ahead market is presented in (Ávila and Papavasiliou, 2024). In this work3F,[4] the authors implement unit-based production simulation models that rely on unit commitment and economic dispatch, and that simulate pertinent features of the co-optimization versus sequential clearing designs. The modeling framework of the authors is particularly developed in order to measure the inefficiency of irrevocable short-term power system scheduling decisions due to the forced separation that takes place between the scheduling of energy and reserves in day-ahead markets. The origin of these coordination losses is attributed to energy price forecast errors which result in erroneous

---

[4] This work is currently under peer review: D. Ávila, A. Papavasiliou, M. Pavesi, M. Viehhauser, "Welfare Benefits of Transitioning to Co-Optimization of Energy and Reserves in Europe".

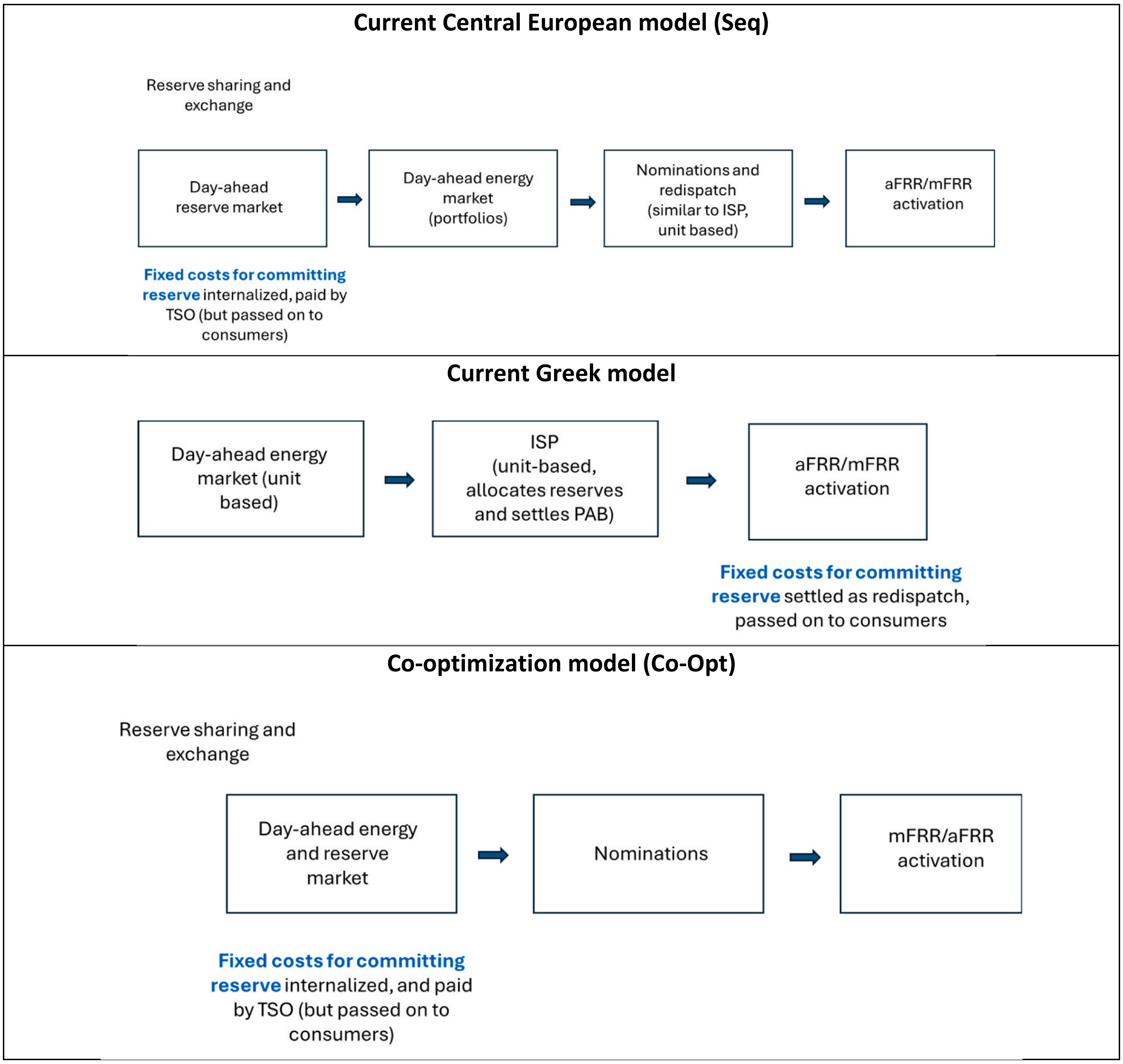

**Fig. 1.** Graphical depiction of three alternative designs. Top: current Central European design advocated by IPTO, denoted as (Seq). Middle: current Greek design. Bottom: future target European design, denoted as (Co-Opt).

estimates of opportunity costs for committing reserves, as well as the fact that quasi-fixed costs (startup and min load) cannot be unambiguously decomposed between the provision of energy and reserves. The analysis shows significant potential economic gains stemming from co-optimization, whereas the sharing of reserves under the existing sequential design reaps only a fraction of these potential gains. Thus, the study shows that there are gains to be had from reserve sharing and exchange, but these gains are maximized when the trading of energy and reserves is co-optimized in the day-ahead market. In this paper, we extend the methodology employed in (Ávila and Papavasiliou, 2024) by introducing an endogenous treatment of hydro scheduling to the model (due to the dominant role of hydro in the Greek market) in order to compare the efficiency losses of a possible implementation of the (Seq) design in Greece instead of waiting for a direct transition to (Co-Opt). A similar modeling framework is adopted in a recent industry report (Consentec, 2025). Although there are various differences between the model of (Ávila and Papavasiliou, 2024) and that of (Consentec, 2025), including but not limited to the treatment of binary variables, the simulation of present versus future system conditions, the treatment of hydro and storage, and the set of sectors that are treated in the model (e.g. hydrogen), it is interesting to note that the modeling framework adopted by (Consentec, 2025) for the simulation of what they refer to as "uncoordinated" sequential clearing is essentially based on (Ávila and Papavasiliou, 2024).

The efficiency gains of co-optimization that are documented in (Ávila and Papavasiliou, 2024) relate to the endogenous treatment of the complex interdependencies of providing energy and reserves within the market clearing model. Energy and reserves are inherently interdependent, and there is a common production factor (fixed startup cost) that cannot be straightforwardly split between the provision of one or the other. For all technologies (both hydro and thermal), reserves and energy are mutually exclusive: the provision of reserves takes up generation capacity that needs to be put aside for the secure operation of the system, and therefore this capacity cannot be used for providing energy in the day-ahead energy market. This places traders in the challenging position of having to estimate opportunity costs for offering reserves in those markets where reserves are cleared before energy. In sufficiently simple settings, these opportunity costs are the difference between the price of energy and the marginal cost of the unit in question. But this implies that errors in forecasting energy prices can result in errors in the forecast of efficient opportunity costs, thereby leading to potential reversals in the "efficient" merit order of the reserve market and thus inefficient commitment of reserve units. In the absence of non-convexities, one can argue (Ávila and Papavasiliou, 2024) that sequential clearing of reserves before energy can lead to identical outcomes as co-optimization if market participants can perfectly anticipate perfectly competitive energy prices, and this poses a fundamental problem for the analysis of (Consentec, 2025) which relaxes binary unit commitment variables and thus falls back to a convex market clearing model. This assumption of perfect anticipation is overly optimistic in practice, given that reserve markets concern 24 time periods (in case of hourly time steps for the next day) with at least four concerned and interacting reserve products (upward/downward mFRR and aFRR). Hydro introduces a further level of complexity, since in the presence of hydro there are opportunity costs for allocating generation capacity between reserve and energy, but also for allocating generation capacity between time periods.

The situation becomes even worse when we move away from convex settings to the more realistic world of non-convexities. Thermal units have startup costs and minimum run levels. Thus, insofar as thermal units are concerned, startup is a common production factor. The equivalence of sequential and co-optimized clearing collapses in this case. In simple words, providing energy requires incurring a fixed cost of starting a unit up, and so does reserve, but starting a unit up means that a thermal unit can provide both energy and reserve. There is no straightforward way of splitting this fixed cost between energy and reserve markets when units are bid into one or the other in sequential designs. Instead, this fixed cost is handled endogenously and optimally in a co-optimized design.

Irrevocable inefficient scheduling decisions can result in inefficient system operations. A major driver of the inefficiencies that are reported in (Ávila and Papavasiliou, 2024) relate to the fact that units with high technical minima are committed aggressively in the day ahead under sequential clearing. They then push low-cost technologies, such as nuclear units, to lower dispatch levels in the day-ahead time frame. Since some of these low-cost technologies are not fully dispatchable in real time, these units are irrevocably run below optimal levels in real time. One could argue that adequate corrections moving close to real time can largely correct these inefficiencies. This is in part true, but is again overly optimistic: why would we expect the intraday and real-time markets to do a better job than the most sophisticated market (the day-ahead energy market in Europe) in committing and dispatching units given that they have less precise representations of network constraints and technical and economic characteristics of generating units (i.e. simpler market products that are less capable of representing relevant costs and constraints)? One could alternatively argue that portfolios could correct these inefficiencies internally. But this then requires large portfolios, and raises concerns of market power. Market power is discussed next.

### 2.3. Market power

A notable pillar of the IPTO proposal is the use of portfolio bidding and pay-as-bid pricing in the proposed design of the reserve market. The unit-based philosophy of the existing design in Greece enables more precise market power monitoring. Moving to portfolios creates a degree of lack of transparency which can prove to be problematic, especially in a market such as the Greek one where there is clearly a single dominant firm (POYRY, 2014), bearing also in mind that market power monitoring and mitigation mechanisms are typically described as unit-based tests (Stoft, 2002), (Hogan and Pope, 2017).

Triggered by this concern, we propose and analyze a model of market power with a dominant firm and fringe competition in sequential versus co-optimized markets for energy and reserves. Concerns about the exercise of market power in reserve markets were voiced already in the early days of deregulation in the US markets (Borenstein et al., 1995). However, to the best of our knowledge there is a shortage of analysis on the scope of exercising market power in interacting auctions for energy and reserve, with previous literature rather focusing on the possible exercise of market power in interacting auctions for energy and transmission, see for instance (Hogan, 1997; Jing-Yuan and Smeers, 1999; Hobbs, 2001).

Our interest in analyzing market power should not be interpreted as a claim that market power only occurs in portfolio-based designs with pay-as-bid pricing. Market power is a matter of market structure, and is a problem in both integrated as well as unbundled systems (Wilson, 2002). And, despite the fact that pay-as-bid pricing induces misrepresentation of cost (Stoft, 2002), the interactions of auction design (in particular, pay-as-bid versus uniform pricing) with efficiency and consumer surplus in the presence of market power does not lead to a conclusive ranking among alternatives (Fabra et al., 2002), (Fabra et al., 2006).

## 3. Methodology

We analyze the proposal of IPTO along three different axes: (i) We use a production simulation model of the Greek electricity market to estimate the efficiency losses of a transition to the (Seq) design relative to the (Co-Opt) design (section 3.1). (ii) Motivated by concerns related to market monitoring and transparency, we analyze market power in energy and reserve markets in a market with dominant firm and fringe competition (section 3.2). (iii) We summarize and critically assess arguments in favor of or against the alternative designs of Fig. 1 that are voiced by market stakeholders (section 3.3).

### 3.1. Production simulation model of Greek electricity market

We proceed to describe our comparison of the (Seq) design which is promoted by IPTO to an idealized co-optimization of energy and reserves. The goal is to understand what the potential efficiency losses of such a proposal could be. The logic of benchmarking against (Co-Opt) is that (Co-Opt) represents a target design that Member States are expected to strive towards in the coming years, see also the related discussion about institutional developments in Europe in section 2.2. The model is based on (Ávila and Papavasiliou, 2024) and is elaborated further in the remainder of this section. The results of the analysis are presented in section 3.2. The assumptions and data sources of our analysis are summarized in Table 1.

We model the Greek market using a unit-based production

**Table 1**
Overview of the characteristics and data sources of our quantitative case study.

| | Characteristics | Data |
|---|---|---|
| Modeled region | Greece | |
| Transmission network | • Nodal (direct current power flow approximation)<br>• Cross-border flows fixed to historical data | • PyPSA<br>• Cross-border flows from 2024 gathered from ENTSOE transparency platform |
| Generation | | PyPSA |
| Load | Yearly time series | • Obtained from PyPSA<br>• Updated to 2024 using ENTSOE transparency platform |
| Reserve products | Upward/downward mFRR/aFRR | Reserve requirements from 2024 gathered from ENTSOE transparency platform (available in (Papavasiliou and Ávila, 2025)) |
| Representative days | Operational year represented through 24 representative days that are selected based on k-medoids algorithm (days listed in (Papavasiliou and Ávila, 2025)) | |
| Day-ahead energy price forecast error | Gaussian noise with 0 mean and standard deviation equal to 3% of energy prices | |

simulation model based on unit commitment and economic dispatch. The network model is nodal, with a standard linear approximation of the optimal power flow equations using DC optimal power flow. Network data is sourced from PyPSA. Cross-border flows are fixed to historical values for 2024 which are sourced from the ENTSOE transparency platform. Generation technical and economic information is sourced from PyPSA. We use a yearly load time series which is obtained from PyPSA. The data is rescaled so as to correspond to the average load values of 2024, as obtained from the ENTSOE transparency platform. Upward and downward aFRR and mFRR are represented in the model, with the reserve requirements of 2024 being sourced from the ENTSOE transparency platform. We approximate an entire year of operation by simulating 24 representative days, which are determined using the k-medoids algorithm. Day-ahead price forecast errors are simulated as Gaussian noise with a zero mean and a standard deviation equal to 3% of the energy price.

**(Seq) design**. The proposal of IPTO is represented as a day-ahead reserve market followed by a day-ahead energy market. The basic model that we develop is depicted in Fig. 2. The reserve market minimizes the sum of fixed costs and opportunity costs of generating units, with opportunity costs corresponding to the profit margin of removing capacity from the energy market in order to sell this capacity as reserve. We adopt the optimistic assumption that the energy price which is used for estimating opportunity cost is based on the energy price of the co-optimization model4F.[5] To this price we add a price forecast error, which corresponds to the fact that producers are not able to accurately estimate the energy price that corresponds to efficient market operation. Minimum up/down times and ramp constraints are accounted for in the reserve clearing model.

After the day-ahead reserve model clears, we solve a day-ahead energy market clearing model. This model is also a unit-based unit commitment model where aFRR and mFRR allocations are fixed based on the output of the day-ahead reserve model. Since the unit commitment model accounts for the interaction between the commitment of a unit and its ability to offer aFRR and mFRR, the model starts units up so that they can offer any aFRR and mFRR capacity that is allocated in the reserve clearing model. Technical minima and maxima are represented in the model, along with ramp constraints and min up/down times. The objective of the day-ahead energy market model is the minimization of involuntary load shedding cost plus fuel cost plus fixed startup and min load cost of thermal units.

**(Co-Opt) design**. The co-optimization model optimizes energy jointly with reserves in a multi-product uniform price auction. aFRR and mFRR are therefore traded jointly with energy. In contrast to the proposal of IPTO, this model directly coordinates the provision of energy and reserves simultaneously. The model includes min up/down time constraints, technical minima and maxima, as well as ramp constraints. The objective of the model is cost minimization while requiring that both energy demand and reserve requirements are covered. System cost includes the cost of involuntary load shedding, the fuel cost of operating a thermal unit at technical minimum, startup cost and variable fuel cost. The co-optimization model does not require price forecast errors as input, since the opportunity cost of allocating capacity for reserve is accounted for and optimized endogenously in the model.

### 3.2. *Market power analysis*

Regulation 1106 of 2024 (REMIT) defines market manipulation as follows (European Parliament, 2024):

> “*entering into any transaction, or issuing, modifying or withdrawing any order to trade or engaging in any other behaviour relating to wholesale energy products which: […] (ii) secures, or is likely to secure, by a person, or persons acting in collaboration, the price of one or more wholesale energy products at an artificial level, […]*”.

The interpretation of what “an artificial level” means in the context of pay-as-bid pricing becomes non-obvious. This is because the rational strategy of even a perfectly competitive market participant under a pay-as-bid design is to *not* submit a truthful offer (Stoft, 2002), but rather to attempt to anticipate the marginal cost of the marginal unit.

Similarly, departing from a unit-based design and transitioning to portfolios undermines the ability of the regulator to monitor the extent to which market offers are representative of underlying units. Concretely, the unit-based design enables the regulator to attribute a specific market offer to a given generation unit. By contrast, because a specific part of the merit order of a portfolio cannot be attributed to a specific part of the marginal cost curve of a given technology, the owner of the portfolio has the opportunity to inflate its costs when bidding into the market.

These two factors can influence the ability of a dominant firm to exercise market power. Motivated by this, in section 4.2 we discuss the comparison of a co-optimization model under perfect competition to a dominant firm model under the (Seq) and (Co-Opt) designs. The two models are compared on a simplified market model in a technical supplement (Papavasiliou and Ávila, 2025), in order to understand the properties of each design option. Here we distill the main assumptions of the analysis. In our simplified analysis, the market consists of one dominant firm, the capacity of which represents a significant share of the installed capacity in the market, as well as a population of fringe competitors that are assumed to be represented by a non-decreasing marginal cost curve and the installed capacity of which is comparable to that of the dominant firm. Moreover, the fringe competitors are assumed to always bid truthfully. The energy market further consists of a non-increasing inverse demand function, which corresponds to the valuation of a price-elastic population of energy consumers. Similarly, the buyer of reserves (i.e. the TSO) is represented by a non-increasing inverse demand function for reserve, which corresponds to the non-increasing willingness of the transmission system operator to pay for increments of reserve capacity.

The analysis developed in (Papavasiliou and Ávila, 2025) is inspired by classical monopoly models. It is not an undertaking to analyze equilibrium outcomes under pay-as-bid pricing (Fabra et al., 2006), since article 4.2 of the ACER methodology (ACER, 2025b) stipulates that participation in reserve sharing and exchange requires marginal pricing. Nor is there any specific distinction within the model between portfolios versus unit-based designs, as is also the case in classical models of strategic interactions in quantities (Salant, 1982). Nevertheless, we find the insights of the analysis non-trivial and to the best of our knowledge such findings are not documented in existing literature. The analysis is confirmed with both analytical models as well as math programming codes.

### 3.3. *Stakeholder arguments*

Over the course of the public consultation which motivated this work, our team reviewed the detailed proposal of IPTO (IPTO, 2024). Furthermore, we engaged in a collection of views from various industry stakeholders (including regulatory authorities, consumer groups, producers, retailers, consultants) regarding the perceived pros and cons of the alternative designs described in Fig. 1 and reviewed the positions that were submitted by market participants in response to the public consultation.[6] A critical assessment of relevant arguments pertaining to

---

[5] Since the co-optimization model is non-convex, by price we are referring to the approximation of convex hull price based on linear relaxation (Hua and Baldick, 2017).

[6] https://www.raaey.gr/energeia/diavoulefseis/116876/.

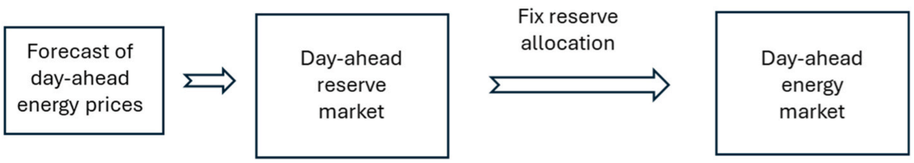

**Fig. 2.** Graphical representation of the modeling implementation of the (Seq) design which we use for efficiency benchmarking of the IPTO proposal for the Greek market.

the public consultation is summarized in section 5.3.

## 4. Results

In the present section we discuss the results of our analysis for the production simulation model (section 4.1) and the market power analysis (section 4.2). The analysis of stakeholder arguments is rather qualitative, therefore there are no quantitative results to present with respect to this axis of our methodology.

### 4.1. *Results of production simulation model*

In this section we discuss the results of our case study. We commence by analyzing the root causes of the efficiency losses of sequential clearing in section 4.1.1. We then discuss the endogenous treatment of hydro and its effect on the results of our analysis in section 4.1.2.

### 4.1.1. *Breakdown of efficiency losses*

Fig. 3 compares the cost of the (Seq) design with that of the (Co-Opt) design. The operation of hydroelectric plants in the results of the figure follows an optimistic assumption whereby the bid structure of the envisioned (Seq) market allows for hydro units to express their precise opportunity cost for participating in reserve markets as a function of the full 24-h time series of energy prices of the subsequent energy market. This assumption is clearly not satisfied in practice, and more realistic assumptions about the expressiveness of the bid structure of the reserve market can lead to efficiency loss estimates that become as high as 8.77% (see Fig. 5 and Table 2) even in the absence of price forecast errors.

As we discuss in section 3.1, modeling the (Seq) design requires sampling price forecast errors. We present results for 100 runs of the (Seq) model for 100 independent samples of price forecast errors. For each run we compute the relative increase in cost of the (Seq) design, i.e. we compute the following quantity:

$$\frac{\text{Cost (Seq)} - \text{Cost (Co} - \text{Opt)}}{\text{Cost (Co} - \text{Opt)}}.$$

In Fig. 3 we present the mean (narrowing of dark band), 25-75% quantiles (width of dark band), as well as outliers (in circles) which correspond to the outcomes beyond the whiskers of the plot. We note that the estimate of average cost increase of the (Seq) design relative to the (Co-Opt) design amounts to 6.76%, with a 95% confidence interval of 6.61%-6.92%. The mean of this distribution corresponds to the total height of the bars in Fig. 4.

In order to explain these efficiency losses, we decompose this cost increase in Fig. 4. We are specifically interested in the decomposition of cost increases in a part that can be attributed to price forecast errors, an inefficiency due to suboptimal dispatch of thermal units, and an inefficiency due to suboptimal coordination between hydro and thermal units.

Efficiency losses related to thermal operation are due to irrevocable and erroneous decisions in the commitment and dispatch of thermal units resulting from the decoupling of energy and reserve markets. We note that these efficiency losses (represented in Fig. 4 in blue) amount to 0.25%. The way in which these inefficiencies are concretely computed is

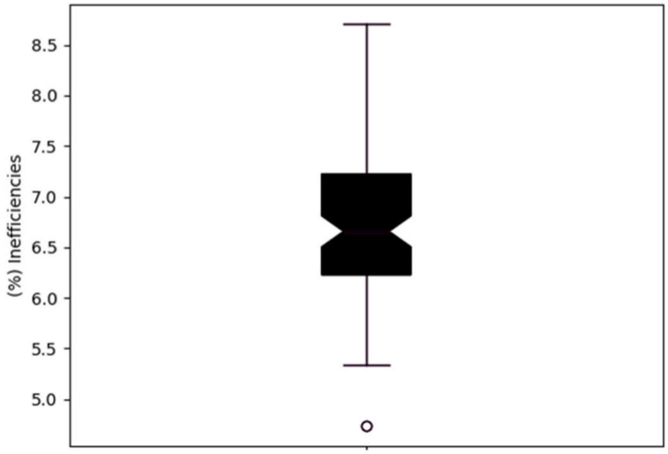

**Fig. 3.** Cost increase of (Seq) design relative to the cost of the (Co-Opt) design. The (Seq) design that we simulate is an idealized design whereby the constraints of hydro plants are represented in full detail by the reserve market bidding products, which is not realistic in practice.

**Table 2**
Performance of the (Seq) design as a function of the amount of power that the hydro plant can utilize for reacting to energy prices, relative to setting the hydro schedule based on the results of the (Co-Opt model).

| Allowed participation in energy market (%) | Increase in cost of (Seq) design (%) |
|---|---|
| 100 | 8.77 |
| 80 | 5.1 |
| 50 | 3.07 |
| 30 | 4.5 |

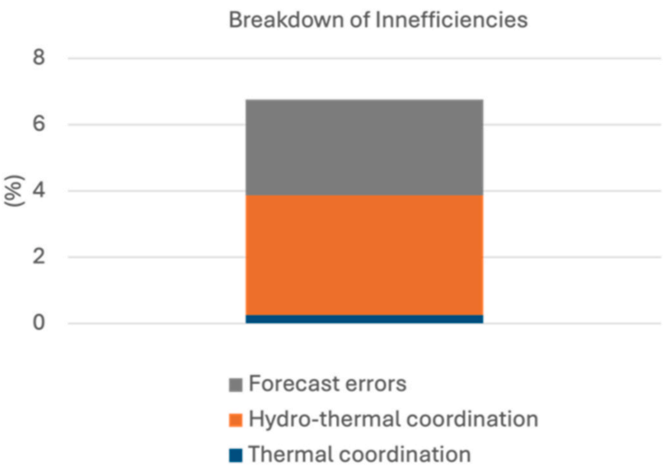

**Fig. 4.** Breakdown of economic inefficiencies of (Seq) design. Efficiency losses due to the suboptimal dispatch of thermal units (blue bar) correspond to 0.25%. Efficiency losses due to suboptimal hydrothermal coordination (orange bar) correspond to 3.62%. Efficiency losses due to day-ahead price forecast errors (gray bar) amount to 2.89%. (For interpretation of the references to color in this figure legend, the reader is referred to the Web version of this article.)

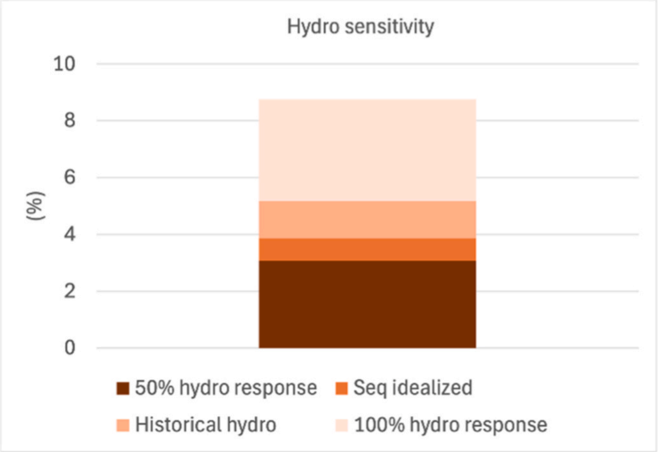

**Fig. 5.** Analysis of the effect of different hydro modeling assumptions on efficiency losses for the (Seq) design relative to (Co-Opt).

by comparing the cost of the (Co-Opt) model with that of the (Seq) model in which we assume zero price forecast errors and where we set the dispatch of hydro units in the (Seq) model equal to that of the (Co-Opt) model. This removes the effect of hydro scheduling from the comparison and rather isolates the effect of the inefficient scheduling of thermal units.

In the case of the Greek system, the role of hydro is crucial, especially insofar as its coordination with thermal units is concerned. The optimal coordination of hydro and thermal units is undermined by the (Seq) design relative to the (Co-Opt) design, and this is indicated by the orange bar in Fig. 4, which amounts to 3.62%. The way in which these inefficiencies are precisely computed is by comparing the cost of the (Seq) model in which the operating point of hydro is set equal to that of the (Co-Opt) design against the cost of the (Seq) model where hydro units are scheduled under optimistic assumptions, i.e. when hydro plants are scheduled based on a bid structure that allows them to express opportunity costs as functions of the *vector* of the price trajectories of the energy market *without* price forecast errors.

Energy price forecast errors lead to an erroneous estimation of opportunity costs of reserve units under the (Seq) design. We underline that the (Co-Opt) design is not subject to such errors because the (Co-Opt) design prices opportunity cost endogenously and optimally since it optimally coordinates the provision of energy with the provision of reserve. We note that these efficiency losses (represented in Fig. 4 with the gray bar) amount to 2.89%. The way in which these inefficiencies are precisely computed is by comparing the cost of the idealized (Seq) model *without* errors in energy price forecasts to the cost of the idealized (Seq) model *with* errors in energy price forecasts.

### *4.1.2. Hydro sensitivity analysis*

Given the crucial role of hydro, a further sensitivity analysis is conducted whereby price forecast errors are lifted for all generators in the system, and we rather employ different assumptions on how hydro schedules are set. This sensitivity indicates a considerable influence of hydro schedules on the efficiency performance of the sequential design. Concretely, we have noticed that system costs are highly sensitive to alternative approaches towards scheduling hydro (see Fig. 5). These alternative scheduling policies are defined precisely below. At this point, and as indicated in Fig. 5, it is worth noting that the cost of the hydro scheduling policy (100% hydro response) is 4.9% higher than that of the hydro scheduling policy (Seq idealized). We repeat that the results of the present section are based on models with perfect energy price forecasts. The introduction of price forecast errors would further exacerbate these efficiency losses.

More specifically, in Fig. 5 we present four alternative assumptions regarding the management of hydro plants. Note that the colors in the figure indicate *difference* in efficiency between models. For instance, the light pink bar corresponds to the difference between (100% hydro response) and (Historical hydro). The most optimistic assumption corresponds to the dark brown color in Fig. 5, and it is referred to in the caption as (50% hydro response). In this model, the amount of power that hydro units can make available in the energy market is limited to 50% of their nominal capacity. This model results in efficiency losses of 3.07% relative to (Co-Opt). The second-best performance6F[7] is attained by the (Seq idealized) design, where the opportunity cost of hydro units is represented as a vector of day-ahead energy prices in the reserve market clearing model. This is precisely the reference model to which we compare the (Co-Opt) design in section 3.2.1. In the absence of price forecast errors, the additional efficiency losses of this model amount to 0.8%, thus leading to total efficiency losses relative to (Co-Opt) that are equal to 3.87%. The additional efficiency losses of this model are indicated with the dark orange bar in Fig. 5. The third best performance is attained by the model corresponding to the light orange bar, in which the operating point of hydro plants is set equal to the historical values of hydro dispatch. This is indicated in the legend of Fig. 5 as (Historical hydro). The additional efficiency losses of this model amount to 1.3%, thus the overall efficiency losses relative to (Co-Opt) in this case amount to 5.17%. The worst performance is attained by a model in which the entire capacity of hydro units is made available in the energy market. This is indicated in Fig. 5 in light pink, and results in additional efficiency losses of 3.6%, with total efficiency losses relative to the (Co-Opt) model amounting to 8.77%. This model is indicated in Fig. 5 as (100% hydro response).

The (50% hydro response) and (100% hydro response) models of Fig. 5 correspond to a family of models that are parametrized with respect to the amount of hydro capacity that we make available to the energy market. Concretely, in the (100% hydro response) model of Fig. 5 the idea is to determine the operating point of hydro plants by allowing these units to react to the energy price of the (Co-Opt) model. If hydro plants are allowed to respond to this price signal with their full capacity, we obtain the operating points (for a typical 24-h interval) that are presented in the blue time series of Fig. 6. We contrast these to the operating points of (Co-Opt) which are also presented in Fig. 6. The figure highlights the shortcoming of the (100% hydro response) model: hydro units are reacting excessively to energy prices, and no capacity is held back for reserve markets during hours 17-19, when energy prices peak. This is the main cause of the 8.77% efficiency losses which are documented in Fig. 5.

When comparing the (50% hydro response) and (100% hydro response) models in Fig. 5, we conclude that the fraction of hydro capacity that we make available to the energy market is a parameter that can strongly influence the performance of the (Seq) design. The effect of this parameter on the performance of the (Seq) design is presented in Table 2. We observe that a high participation (e.g. 100%) results in poor performance, due to the fact that hydro plants react excessively to the energy price and this does not allow sufficient space for hydro plants to engage in the reserve market, as we have already observed in Fig. 6. By contrast, a low (e.g. 30%) amount of participation of hydro in the energy market also leads to poor performance, since hydro units are not granted adequate capacity to flatten the marginal cost of the system between time periods. Such challenges are not relevant for the (Co-Opt) design, where thermal and hydro units are coordinated jointly in the provision

---

[7] Note that the comparison of (Seq) to (Co-Opt) in section 3.2.1 uses (Seq idealized) as the benchmark sequential clearing model, not (50% hydro response), despite the fact that the latter performs slightly better for this specific case study of the Greek system. We do this since (Seq idealized) does not require a tuning of the amount of hydro response, and is thus invariant to both the specific system characteristics as well as the specific days that are being analyzed.

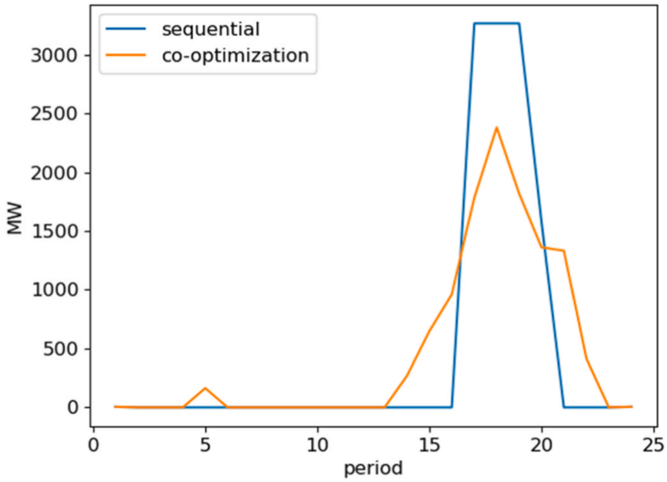

**Fig. 6.** Setpoints of hydro plants in the (100% hydro response) model of the (Seq) design and in (Co-Opt). The installed hydro capacity is 3265 MW. The simulated day is January 17, 2024. The simulations present a similar behavior across different representative days.

of both energy and reserve. The optimal performance of the (Seq) design is attained in our case study when hydro units are granted a degree of participation of 50% in the energy market, as indicated in Table 2. This corresponds to the (50% hydro response) variant of Fig. 5.

### *4.2. Results of market power analysis*

Our analysis of joint energy and reserve markets (Papavasiliou and Ávila, 2025) is inspired by the classic microeconomic model of a dominant firm in a single market (Salant, 1982), (Gabriel et al., 2012). Our basic results uncover some differences in the scope of exercise of market power in co-optimized versus sequential clearing designs. Nevertheless, the main intuition of the classic model of the dominant firm persists: monopolies tend to withhold quantities to inefficiently low levels in order to increase prices to the point of equalizing marginal revenues with marginal costs. The fact that there are two interacting markets does complicate the analysis, but does not cancel the basic intuition.

In the model of perfect competition with co-optimization of energy and reserves, a multi-product uniform price auction clears energy and reserve jointly. As long as there is sufficient power to fill the entire inverse demand function for reserve, the price of reserve is zero, since reserve can be fully served, if necessary even by high-cost fringe producers that are not being deployed in the energy market. As long as the technology of the dominant firm is sufficiently cheap to cover energy demand, this implies that the marginal cost of this technology determines the marginal cost of the fringe suppliers that are called upon to cover the energy demand, and this in turn sets the energy clearing price. Thus, the overall behavior of the model leads to a reserve price that is equal to zero and an energy clearing price that is equal to the marginal cost of the dominant firm.

In the monopoly model under the (Seq) design, it is necessary to represent the opportunity cost of the dominant firm as a function of the amount of reserve that is offered by *both* the dominant firm as well as the fringe competitors. These two factors jointly determine the energy clearing price at the second stage of the model, when the energy market is cleared. At the first stage of the model, the dominant firm equalizes its marginal revenue from trading reserves with the marginal opportunity cost of the reserve market. A crucial aspect of the monopoly behavior of the dominant firm is the fact that the dominant firm realizes that by reducing the amount of reserve that it makes available in the reserve market it may on the one hand reduce its market share, however on the other hand it can increase the price of the reserve market. This is what leads to withholding reserve by the dominant firm in the first stage of reserve market clearing. Fringe producers also adjust their offered reserve quantities, taking into account the fact that cheaper units are expected to be cleared in the energy market which clears after the reserve market. In the second stage, when the energy market clears, and *given* the reserve that is committed by both the dominant firm and fringe competitors, we fall back to a classic dominant firm model in which the dominant firm equalizes its marginal revenue to its marginal cost in the energy market, but keeping in mind that withholding output from the energy market may reduce the market share of the dominant firm while increasing energy prices. The final outcome of the model is that both energy and reserve prices increase, and so does the profitability of the dominant firm. The analysis is demonstrated on a simple illustrative example in the technical supplement of (Papavasiliou and Ávila, 2025).

In the monopoly model under the (Co-Opt) design, the monopolist applies a strategy of equalizing marginal revenue to marginal cost on the joint energy and reserves auction. Both energy and reserve prices are joint functions of the production and reserve quantities of the dominant firm, thus the opportunity cost of committing reserve in this model is reflected directly in these prices, which are implicit functions of energy and reserve quantities. This contrasts with the sequential clearing model, where the opportunity cost of providing reserve in the reserve auction is computed by solving a subsequent profit maximization problem for the agent in the energy market clearing stage.

## 5. Discussion

We discuss our findings in the present section. Section 5.1 focuses on the results of the production simulation model (see section 3.1), section 5.2 discusses the market power analysis (see section 3.2) and section 5.3 discusses certain relevant points from our engagement with stakeholders (see section 3.3).

### *5.1. Discussion on production simulation modeling*

In this section we proceed to discuss some caveats related to our analysis. As in the case of (Ávila and Papavasiliou, 2024), we resort to a unit-based unit commitment and economic dispatch model instead of attempting to model the precise bidding products of the Greek exchange. We also do not model the precise idiosyncrasies by which European day-ahead markets treat the pricing of non-convexities (in particular, the rules that drive block orders from being rejected from the order book when equilibrium prices do not exist for supporting a specific matching of block orders). The use of a unit-based model is also the case in (Consentec, 2025), although the analysis of (Consentec, 2025) does not use binary variables7F.[8] We resort to unit-based models in order to be able to conduct our analysis based on available data. Co-optimization is yet to be implemented in the common European market, thus no bidding data is available for this design. Therefore, the only way to proceed with our analysis given available data is a unit-based model.

A related point is that co-optimization, as contemplated currently by European stakeholders, is considered on a portfolio basis. To the best of our knowledge, there are no satisfactory models at the moment in the literature for mapping the costs and constraints of portfolios to market bids that respect the European market bid structure which are scalable to the level of system simulation and equilibrium computation, although efforts are underway for developing such models from the standpoint of individual market participants (Karasavvidis et al., 2021), (Karasavvidis et al., 2023). Effects can be mixed: on the one hand, firms with large

---

[8] Ignoring binary variables is fundamentally problematic in the analysis of (Consentec, 2025) since it can be proven mathematically (see the reference in footnote 4 and (Papavasiliou, 2024)) that in a convex market model sequential and co-optimized market clearing achieve the same efficiency when market participants can anticipate the perfectly competitive energy price.

portfolios can coordinate their bids internally, thereby achieving a similar effect to co-optimization. However, this presumes large portfolios, which are problematic in terms of market power. On the other hand, bid structure can result in a loss of an important amount of information. Until the precise bid structure of envisioned portfolio-based European markets with co-optimization is clarified, which is part of the effort underway within SDAC (MCSC SDAC, 2025), (MCSC, 2025), (ACER, 2025a), it is precarious to say something specific on this issue based on quantitative modeling. The mapping of the technical and economic characteristics of individual assets within a portfolio to specific bid structures would also need to be further advanced as an area of research so as to be able to conduct system-level simulation before specific quantitative analysis can be conducted on this front.

Another important caveat of our analysis is that we analyze the current conditions of the Greek system. This is as opposed to attempting to model future conditions in the Greek market. Future conditions may differ markedly: (i) renewable resources (and correspondingly renewable curtailments) are expected to be intensified, (ii) a significant amount of additional storage is anticipated in the system, (iii) different load and import/export patterns may be expected, to name a number of factors. Especially insofar as storage is concerned, we document a strong sensitivity of our results to the precise coordination of (hydroelectric) storage in section 3.2.2. Given the inherent disadvantage of sequential designs in coordinating opportunity costs across products and time, it can therefore be expected that we may be underestimating the efficiency losses of sequential clearing in a future scenario of the Greek system.

The discussion of the previous paragraph highlights another limitation of our analysis: our efficiency loss estimates exhibit a non-negligible range. As we explain in section 3.2.2, efficiency losses may vary between 3.07% and 8.77% in the absence of energy price forecast errors, depending on how hydro is treated. An inefficiency of 3.07% is already quite significant, however a precise cost-benefit analysis of the contemplated design change promoted by IPTO should bear this sensitivity into account.

As previous analysis at the level of the Core region (Ávila and Papavasiliou, 2024) has shown, intraday and close-to-real-time corrections can come a long way in restoring efficiency losses by re-positioning the system with those decisions that can still be updated from the day ahead to real time. The case study of the Core region (Ávila and Papavasiliou, 2024) has shown that this can shave the efficiency losses of the sequential design by approximately half. In this sense, therefore, our analysis is exaggerating the potential efficiency losses of sequential clearing. However, achieving this correction stumbles upon either the requirement of portfolio coordination (i.e. an assumption of high market concentration, which creates asymmetric advantages for a potential dominant firm), unit-based out-of-market interventions through redispatch, or the paradox whereby the European intraday and real-time markets perform better at coordinating resources than the European day-ahead market. The latter would indeed be surprising, since the European day-ahead market has garnered far greater effort in its design than its less sophisticated intraday and real-time counterparts.

Pricing is out of scope for this paper, and the analysis rather focuses on efficiency. As discussed in section 3.1, the linear programming relaxation of the co-optimization model is used for estimating what agents anticipate the energy prices of the market to be under the (Seq) design, which is a necessary input for estimating opportunity costs. However, other alternatives exist for pricing in non-convex markets. Interesting areas of future work include the analysis of how such pricing conventions affect the performance of the (Seq) design and how pricing compares under the (Seq) versus (Co-Opt) designs under different non-convex pricing mechanisms.

Finally, it is worth underlining that no attempt has been made in our work to compare the IPTO proposal to the *existing* Greek design. As we explain in section 2.1, the existing design in Greece is also a sequential clearing where reserves are allocated after the day-ahead energy market through ISP (even if ISP is itself based on a co-optimization formulation). Our comparison in section 3.1 is targeted purely on comparing the IPTO proposal to a *future* co-optimization design.

### 5.2. Discussion on market power analysis

An interesting and non-obvious observation of our analysis is that the precise distinction between sequential and co-optimized clearing does not affect the equilibrium outcome significantly. Although we do not provide generalizable results on the equilibrium outcome, we observe in the case of a specific numerical example (table 3 of (Papavasiliou and Ávila, 2025)) that welfare decreases by 6.88% under sequential clearing versus 5.9% under co-optimization. Although this observation is of course specific to the chosen numerical example, it is interesting to note that it was not expected at the outset of our analysis. As such, it indicates that market power is a serious problem for either sequential or co-optimized clearing. Fundamental solutions to market concentration that are discussed in (Wilson, 2002) include ownership (e.g. divestiture plans for the dominant firm), forward contracting (Allaz and Vila, 1993) or re-regulation in the form of market monitoring. The relation between the IPTO proposal (in particular, portfolio bidding and pay-as-bid pricing) and market monitoring is discussed in section 2.3.

One assumption of our analysis that is important to make explicit is that we do not attempt to model pay-as-bid pricing in our market power analysis. Instead, we assume uniform pricing in both energy and reserve markets. As we explain in section 3.2, we choose to do so because, according to article 4.2 of the ACER methodology (ACER, 2025b), participation in reserve sharing and exchange requires marginal pricing and thus, even if the IPTO proposal envisions pay-as-bid pricing and even if pay-as-bid pricing is the current practice in certain EU Member States this does not appear to be where the EU market design is headed.

### 5.3. Discussion on stakeholder arguments

In this section we describe and discuss certain arguments that have been used for supporting the proposal of IPTO (IPTO, 2024).

**Reserve sharing and exchange**. One argument that is used for favoring the abolishment of ISP in Greece and transitioning to the (Seq) design which is the status quo in Central Europe is the fact that it enables Greece to participate in the exchange and sharing of reserves. There are valid grounds for pursuing reserve sharing and exchange, since both can in principle decrease the global cost of procuring reserves. There is however one thorny complication: according to article 4.2 of the ACER methodology (ACER, 2025b), participation in reserve sharing and exchange requires marginal pricing of reserve. Instead, an important pillar of the IPTO proposal is reliance on pay-as-bid pricing in the reserve market. The requirement for marginal pricing has in fact acted as a deterrent for, or raised complaints with, the participation of certain Member States in the reserve sharing and exchange platform of the Core region.

**Reduction in uplift costs**. There has been a notable increase in uplift costs recently in Greece. These uplift costs relate, to a certain extent, to the startup of units that provide reserve. Two uplift accounts exist in the Greek market for this reason: uplift account 2 is intended for remunerating reserve commitment costs, and includes pay-as-bid settlements for committing units at the ISP stage, and uplift account 3 is intended for remunerating redispatch costs (these include costs borne by the TSO for bringing reserve units online and at their technical minimum and moving certain other units downward in order to render the overall transaction energy neutral). Uplift account 3 has increased notably in the recent past.

The costs of uplift accounts 2 and 3 of the Greek market are essentially costs for committing reserves. To the extent that these costs relate to competitive costs for committing reserve capacity, the alternative (Seq) design will mirror them in a different part of the market, namely in the price of the reserve market. This may be a more transparent way to reflect the costs of reserve, but it does not imply that the costs of committing reserve will disappear. To the extent that these uplifts are driven by non-competitive forces, this would merit further investigation, and we have no view or opinion on this matter. But the literature indicates that a portfolio-based design would complicate market power monitoring (POYRY, 2014) with references to market power monitoring being rather linked to unit-based systems (Hogan and Pope, 2017), which motivates the analysis of market power described in sections 3.2, 4.2, 5.2.

**Renewable energy curtailments**. As indicated in the opening remarks of section 1, renewable energy curtailments have rocketed in Greece in the last few years. There has been a claim that transitioning to the (Seq) design can improve this situation. The logic of this claim is unclear. The fact that renewable energy is currently curtailed after the ISP run does not mean that ISP is the root cause of these curtailments. The root cause is that there is a surplus of energy, especially when one accounts for the technical minimum of units that are required for covering the reserve requirements of the system. Curtailments would occur also under the (Seq) design, because units would need to operate at their technical minimum, even if the decision to commit these units is made *before* (as opposed to *after*) the day-ahead energy market clears. In fact, the simulation model of section 4 (see section 3.2 of (Papavasiliou and Ávila, 2025)) suggests that renewable energy curtailments *increase* under the (Seq) design, which is consistent with the higher cost of the design.

**Speed of resolution of ISP**. Concerns have been raised about the amount of time that is needed for data transfers and algorithmic resolution of the ISP model. Multi-stage combined cycle units have been cited as being particularly problematic. ISP is effectively a mixed integer unit commitment model. The scientific literature tackles these problems in massive scale, much larger scale than that of the Greek system, which is a relatively small system. Considering the PJM market alone, it has been possible to solve problems with 1200 generation units, 10000 demand bids, 50000 virtual bids, 8700 nodes, over 6000 monitored network elements, and 10000 contingencies, with unit-based unit commitment models since more than 15 years. By comparison, the Greek system is approximately two orders of magnitude smaller and industrial-grade commercial solvers that are used for the resolution of such mixed integer programs and the processors on which these algorithms are run have progressed impressively in recent years.

Solution time issues are certainly a function of the time that is available to the TSO for resolving the ISP. For instance, if less than a few minutes are available for solving the ISP, then the solution time requirement may become more relevant. However, it would need to be better understood what the available time is, and whether it can be increased, given that the ISP is still run in advance of real-time operations, hours before actual dispatch. For instance, contingencies may place tighter run time requirements on unscheduled ISP runs. Nevertheless, all these issues deserve further scrutiny. As a matter of principle, the argument of limited run time is at odds with the state of the art in the commercial and academic domain of optimization algorithms.

**Participation in MARI platform**. It has been argued that the transition to the (Seq) design would allow Greece to participate in the MARI platform. Insofar as participating in MARI is concerned, there is no incompatibility between ISP (or co-optimization for that matter) and participating in MARI. We note that article 27 of regulation 2017/2195 (European Commission, 2017) allows transmission system operators that rely on ISP considerable flexibility in converting market offers so as to align them with the usual products that are traded on the MARI platform. An interesting case in point is Italy, which uses an ISP, and has also participated in the PICASSO platform8F,[9] with an intent to connect to the MARI platform.

**Double-payment of reserve units**. It has been argued that the existing design results in double-payment of reserve units, because these units receive uplift payments for their startup in real time. Fixed costs for committing units are not expected to be paid for twice in a competitive market, because if this were the case then the market share of a unit that is enjoying double payments would be undercut by a more competitive market participant that receives a lower payoff from the market. Startup costs that are incurred in the current design in Greece may very well be internalized under the (Seq) design in the offers of market participants in the reserve markets, resulting in higher prices for reserves. It is further worth noting that aFRR balancing capacity prices in Belgium (which adheres to the (Seq) design proposed by IPTO) rocketed during the 2020-2022 energy crisis. This is because the startup cost of reserve units was internalized in the offers of these units in the Belgian reserve market, with a corresponding increase taking place in the reserve market clearing price. A further observation that supports this view is that the ACER dashboard9F[10] reveals that aFRR and mFRR prices in Greece are notably lower than those observed in other parts of Europe, and certainly the Core region prices (i.e. the prices of the region that the IPTO proposal seeks to emulate). For instance, prices in 2023 averaged 2.02 €/MWh for downward aFRR and 5.01 €/MWh for upward aFRR in Greece, whereas they amounted to 16.62 €/MWh for downward aFRR and 55.34 €/MWh for upward aFRR in Belgium. Similarly, upward mFRR in Greece averaged 0.49 €/MWh in 2023 whereas it averaged 12.00 €/MWh in Belgium (no downward mFRR is reported for Belgium).

## 6. Conclusions

We summarize the main conclusions of our qualitative and quantitative analysis. The conclusions presented below are a mixture of observations from the literature (points (i), (vi)), related to arguments that have been debated by stakeholders (points (ii), (iv), (vii)), resulting from quantitative analysis based on our production simulation model (point (v)), or resulting from our analytical modeling of market power (point (iii)).

Unit-based designs allow for improved market monitoring (POYRY, 2014) (with market monitoring typically phrased in unit-based contexts (Hogan and Pope, 2017)), a transparent representation of system constraints and their associated cost under truthful bidding, and a more accurate representation of the interaction of energy and reserves. (ii) Despite concerns about the transparency of uplift payments in the existing unit-based design in Greece, it is not clear that the transition to sequential clearing would reduce the costs of securing reserves. It is worth noting that Central European markets currently exhibit reserve market clearing prices that are substantially higher than those of Greece, and it is worth reflecting to what extent these higher prices correspond to reserve units recovering startup and minimum load costs. (iii) Transition to a portfolio-based design and pay-as-bid pricing in reserve markets complicates market power monitoring and, therefore, mitigation. Hence, such a transition raises concerns in a highly concentrated market. Concretely, our analysis in section 4.2 shows increase in the price of both energy and reserves under both sequential and co-optimization designs in a market with a dominant firm and fringe competition. Such price increases would then be more difficult to monitor and mitigate under portfolio bidding and pay-as-bid pricing (as opposed to unit-based bidding and uniform pricing). (iv) Co-optimization is currently under serious investigation by ACER and SDAC. The proposal set forth by the Greek TSO, which could require significant effort and delay to deploy, is contrary to this momentum towards co-optimization. (v) The sequential clearing of reserves which is favored by IPTO results in economic inefficiencies relative to unit-based co-optimization because the decoupling of energy and reserve

---

[9] Italy was participating in PICASSO until March 2024 but interrupted its participation temporarily due to high prices on the platform. Nonetheless, reconnected to PICASSO in late 2025, and also plans to connect to MARI.

[10] https://www.acer.europa.eu/media/charts/progress-eu-electricity-wholesale-market-integration-2024-market-monitoring-report.

scheduling leads to errors in the short-term planning of the system. Efficiency losses for the Greek system, barring intraday and real-time corrections, are estimated at 6.61%-6.92% based on a production simulation model of the Greek electricity market and optimistic assumptions regarding the ability of the reserve market bid structure to express the opportunity costs of hydro resources. (vi) Pay-as-bid pricing for reserves contravenes European regulations on reserve exchange (ACER, 2025b). (vii) It is difficult to argue that it is computationally challenging to resolve the Greek ISP within acceptable run times given the academic and industry state of the art in optimization.

These arguments underscore the fact that the current proposal of IPTO should be carefully considered, in terms of its anticipated costs and benefits, before launching a lengthy and laborious effort to uproot the existing reserve market design. Instead, it may be preferable to wait out the evolutions that are taking place at EU level for transitioning to a co-optimized clearing of day-ahead energy and reserve by focusing on improving the current implementation of ISP in Greece.

## CRediT authorship contribution statement

**Anthony Papavasiliou:** Writing – review & editing, Writing – original draft, Validation, Supervision, Project administration, Methodology, Investigation, Funding acquisition, Formal analysis, Conceptualization. **Daniel Ávila:** Writing – review & editing, Writing – original draft, Software, Methodology, Investigation, Formal analysis.

## Declaration of competing interest

The authors declare the following financial interests/personal relationships which may be considered as potential competing interests: Anthony Papavasiliou reports financial support was provided by Hellenic Association of Independent Power Producers. Anthony Papavasiliou reports a relationship with European Union Agency for the Cooperation of Energy Regulators that includes: consulting or advisory. If there are other authors, they declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

## Acknowledgments

This work has received funding from the European Research Council (ERC) under the European Union Horizon 2020 research and innovation program [Grant agreement 850540].

## Data availability

The data sources used by the authors are described in the article.

## References

ACER, 2025a. ACER's Assessment of the R0 Report. Ljubljana: ACER.
ACER, 2025b. Methodology for Harmonising Processes for the Allocation of cross-zonal Capacity for the Exchange of Balancing Capacity or Sharing of Reserves. ACER, Ljubljana, Slovenia.
Allaz, B., Vila, J.-L., 1993. Cournot competition, forward markets and efficiency. J. Econ. Theor. 59 (1), 1–16.
Avila, D., Papavasiliou, A., 2024. Welfare Benefits of co-optimising Energy and Reserves. National Technical University of Athens, Athens, Greece.
Borenstein, S., Bushnell, J., Kahn, E., Stoft, S., 1995. Market power in California electricity markets. Util. Policy 5 (3-4), 219–236.
Consentec, 2025. Assessment of Potential Social Welfare Generated by Combining or Coordinating Portfolio-based Markets for Scheduled Energy and Balancing Capacity. Consentec, Aachen, Germany.
ELIA, 2023. *Terms and Conditions for Balancing Service Providers for Manual Frequency Restoration Reserve (mFRR),* Brussels, Belgium: ELIA.
ELIA, 2024. *Balancing Service Providers Contract for the Automatic Frequency Restoration Reserve (aFRR) Service,* Brussels, Belgium: ELIA.
ENTSO-E, 2021. Implementation Impact Assessment for the Methodology for a co-optimised Allocation Process of cross-zonal Capacity for the Exchange of Balancing Capacity or Sharing of Reserves. ENTSO-E, Brussels, Belgium.
European Commission, 2017. Commission Regulation (EU) 2017/2195 of 23 November 2017 Establishing a Guideline on Electricity Balancing. European Commission, Brussels, Belgium.
European Parliament, 2024. Regulation (EU) 2024/1106 of the European Parliament and of the Council of 11 April 2024 amending Regulations (EU) No 1227/2011 and (EU) 2019/942 as regards improving the Union's protection against market manipulation on the wholesale energy market. Off. J. Eur. Union.
Fabra, N., Von der Fehr, N.-H., Harbord, D., 2002. Modeling electricity auctions. Electr. J. 15 (7), 72–81.
Fabra, N., von der Fehr, R.-H., Harbord, D., 2006. Designing electricity auctions. Rand J. Econ. 37 (1), 23–46.
Farahmand, H., et al., 2012. Balancing market integration in the Northern European continent: a 2030 case study. IEEE Trans. Sustain. Energy 3 (4), 918–930.
Gabriel, S.A., et al., 2012. Complementarity Modeling in Energy Markets. Springer Science & Business Media, Berlin, Germany.
Gan, D., Litvinov, E., 2003. Energy and reserve market designs with explicit consideration to lost opportunity costs. IEEE Trans. Power Syst. 18 (1), 53–59.
Gomez, T., et al., 1999. Ancillary Services Market in California. LBNL, Berkeley, CA.
Hobbs, B.E., 2001. Linear complementarity models of Nash-Cournot competition in bilateral and POOLCO power markets. IEEE Trans. Power Syst. 16 (2), 194–202.
Hogan, W., Pope, S., 2017. Priorities for the Evolution of an energy-only Electricity Market Design in ERCOT. FTI consulting s.l.
Hogan, W.W., 1997. The energy journal. A market power model with strategic interaction in electricity networks 18 (4), 107–141.
Hua, B., Baldick, R., 2017. A convex primal formulation for convex hull pricing. IEEE Trans. Power Syst. 32 (5), 3814–3823.
IPTO, 2024. *Basic Design Principles for Balancing Capacity Auctions and the Integrated Scheduling Process,* Athens, Greece: Dirctorate of Regulatory Affairs and Networks.
Jing-Yuan, W., Smeers, Y., 1999. Spatial oligopolistic electricity models with Cournot generators and regulated transmission prices. Oper. Res. 47 (1), 102–112.
Karasavvidis, M., Papadaskalopoulos, D., Strbac, G., 2021. Optimal offering of a power producer in electricity markets with profile and linked block orders. IEEE Trans. Power Syst. 37 (4), 2704–2719.
Karasavvidis, M., Papadaskalopoulos, D., Strbac, G., 2023. Optimal offering of energy storage in electricity markets with loop blocks. IEEE Trans. Power Syst. 39 (1), 299–315.
Liu, Y., et al., 2002. Implementing rational buyer's algorithm at California ISO. IEEE Power Engineering Society Winter Meeting. New York, NY.
MCSC SDAC, 2025. Co-optimisation of Energy and Balancing Capacity in SDAC Phase 1 R&D Report (R0) on Bidding Products, Bid Design and Pricing. s.l.: MCSC SDAC.
MCSC, 2025. Q&A from the Co-Optimisation R0 Public Consultation Webinar. MCSC s.l.
Morales, J.M., Conejo, A.J., Pérez-Ruiz, J., 2009. Economic valuation of reserves in power systems with high penetration of wind power. IEEE Trans. Power Syst. 24 (2), 900–910.
N-SIDE AFRY, 2020. Cross-Zonal Capacity Allocation with co-optimization. Louvain la Neuve, Belgium: N-SIDE AFRY.
N-SIDE, 2022. Co-Optimization of energy and balancing capacity in the European single day-ahead coupling. Louvain la Neuve, Belgium: N-SIDE.
Oren, S., 2001. Design of Ancillary Service Markets. Maui, Hawaii, HICSS.
Papavasiliou, A., 2024. Optimization Models in Electricity Markets. Cambridge University Press, Cambridge, UK.
Papavasiliou, A., Ávila, D., 2025. Electronic Supplement: Efficiency and Market Power Analysis of Alternative Reserve Market Design Proposals: a Case Study of Greece. National Technical University of Athens, Athens, Greece. https://ap-rg.eu/wp-content/uploads/2026/02/ESUP2026.pdf.
POYRY, 2014. Greek market design: future market design recommendations. Poyry management consulting s.l.
Read, E.G., 2010. Co-optimization of energy and ancillary service markets. In: Rebennack, S. (Ed.), Handbook of Power Systems. Springer Berlin Heidelberg, Berlin, Heidelberg, pp. 307–327.
Salant, S.W., 1982. Imperfect competition in the international energy market: a computerized Nash-Cournot model. Oper. Res. 30 (2), 252–280.
Smeers, Y., Martin, S., Aguado, J.A., 2021. Co-optimization of energy and reserve with incentives to wind generation. IEEE Trans. Power Syst. 37 (3), 2063–2074.
Stoft, S., 2002. Power System Economics: Designing Markets for Electricity. IEEE press, Piscataway.
Wilson, R., 2002. Architecture of power markets. Econometrica 70 (4), 1299–1340.
Wu, T., Angelidis, G., Papalexopoulos, A., Morris, J., 2005. Market Redesign and Technology Update Tutorial for Market Participants. CAISO, Folsom, CA.
Zheng, T., Litvinov, E., 2006. Ex post pricing in the co-optimized energy and reserve market. IEEE Trans. Power Syst. 21 (4), 1528–1538.
Zheng, T., Litvinov, E., 2008. Contingency-based zonal reserve modeling and pricing in a co-optimized energy and reserve market. IEEE Trans. Power Syst. 23 (2), 277–286.