

Article

A Bilevel Multi-Market Coupling Optimization Framework for Nuclear Power Integration: Joint Modeling of Energy, Reserve, and Capacity Markets

Peng Ji ¹, Yiman Liu ², Nan Li ² and Zhongfu Tan ^{2,*}

¹ Beijing Power Exchange Center, Beijing 100031, China

² School of Economics and Management, North China Electric Power University, Beijing 102206, China

* Correspondence: tanzhongfu@sina.com

Abstract

This paper develops a bilevel multi-market coupling optimization framework to analyze the strategic participation of nuclear power plants in modern electricity systems where energy, reserve, and capacity markets are simultaneously cleared. The upper-level problem represents the Independent System Operator's objective of maximizing system-wide social welfare under network, reserve, and carbon-cap constraints, while the lower-level problem captures the nuclear operator's profit maximization subject to ramping limits, minimum uptime requirements, fuel-cycle depletion, and deliverability restrictions. By embedding these technical constraints into a bilevel structure reformulated through tractable complementarity conditions, the model captures the interdependence of nuclear scheduling, reserve deployment, capacity commitments, and carbon compliance in a single optimization environment. The proposed framework is applied to a stylized but realistic case study with 96-h time resolution, 12-bus network topology, and detailed representations of wind variability, demand elasticity, and emission caps. The model quantifies how nuclear participation displaces 40,000 tCO₂ over the horizon, raises producer surplus by 12 percent, and increases total social welfare by nearly 18 percent when all three markets are coupled, relative to an energy-only benchmark. Nuclear profitability is shown to be highly sensitive to renewable volatility, with ± 20 percent swings in wind uncertainty altering profits by 0.24 million USD. Reserve deliverability emerges as the second most influential driver, while policy variables such as carbon price shifts play a smaller role. Reliability analysis based on the complementary cumulative distribution of unserved energy demonstrates that joint market clearing reduces the probability of load shedding at the 0.5 percent threshold from 8 percent in energy-only markets to 2 percent under full coupling. Overall, the study provides the first integrated modeling treatment of nuclear bidding across energy, reserve, and capacity markets within a bilevel optimization framework. By jointly considering operational constraints and policy targets, the framework reveals how nuclear power can simultaneously improve economic efficiency, enhance system reliability, and support carbon mitigation. The results highlight that nuclear's value extends well beyond baseload energy provision, with multi-market strategies offering measurable gains for both individual operators and social welfare under conditions of uncertainty and constraint.



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Keywords: nuclear power integration; bilevel optimization; multi-market coupling; reserve and capacity markets; carbon-constrained electricity systems; social welfare analysis

1. Introduction

Electricity markets across the globe have undergone profound changes as liberalization, renewable integration, and climate policy have converged to reshape how energy is generated, traded, and consumed [1,2]. The once relatively straightforward architecture of vertically integrated utilities and cost-of-service regulation has given way to complex systems of interconnected markets in which multiple products—energy, reserves, capacity, and environmental credits—are simultaneously priced and cleared [3,4]. Within this evolving landscape, nuclear power occupies an increasingly contested yet essential role. Long regarded as the quintessential baseload resource, nuclear plants were traditionally operated at constant output levels to maximize utilization and recover high fixed costs [5,6]. However, in systems with high shares of intermittent renewables, nuclear power is no longer insulated from short-term market volatility or long-term policy uncertainty. Instead, it must navigate the coupled architecture of modern electricity markets, where decisions in one arena, such as capacity commitments, reverberate across energy and reserve outcomes, and where equilibrium prices are continuously shaped by the strategic interactions of diverse participants [7,8].

Much of the early research in market modeling was devoted to welfare-maximizing formulations for system operators. These classical contributions, grounded in optimization theory and power systems engineering, developed the familiar structure of social welfare maximization subject to nodal balance, transmission constraints, and security requirements [9,10]. Locational marginal pricing emerged from this framework as the mechanism by which the cost of generation and congestion is internalized into market outcomes. Yet these models were largely designed with flexible thermal generation in mind and abstracted away from the distinctive technical and economic characteristics of nuclear facilities. Nuclear power was often treated as a must-run resource, producing at fixed levels irrespective of market signals. While such an abstraction was appropriate under regulated regimes, it obscures the strategic complexities of nuclear participation in contemporary liberalized systems [11].

As market designs evolved, so too did the academic focus. Researchers quickly recognized that energy markets cannot be separated from ancillary services if efficiency is to be preserved. Co-optimization of energy and reserves became a dominant theme, with models demonstrating how opportunity costs should be reflected in scarcity pricing [10–12]. Generators were assumed to simultaneously bid for energy and reserves, and system operators were tasked with clearing both products in an integrated fashion. Although these approaches significantly enhanced realism, they did not distinguish between technologies with different capabilities. For nuclear power, whose minimum generation levels are high and whose ramping flexibility is limited, the simple assumption of uniform reserve provision glosses over fundamental operational restrictions. Thus, while the literature advanced the theoretical sophistication of market coupling, it left open the question of how specific technologies like nuclear fit into these designs [13–15].

The introduction of capacity markets added yet another dimension. Motivated by concerns over long-term adequacy, policymakers introduced mechanisms to remunerate availability in addition to short-term energy and reserves. Academic models captured these arrangements through bilevel formulations that linked investor commitments in capacity markets to operator decisions in energy dispatch. Some studies illustrated how capacity payments stabilize revenue streams for capital-intensive technologies and mitigate the missing money problem. However, nuclear power, with its multi-decade investment horizon and uniquely inflexible fuel cycles, remained underexplored in these settings. Unlike peaking units, which thrive in capacity markets by offering flexibility, nuclear plants must reconcile long-term availability obligations with short-term operational rigidity, a balancing act inadequately captured in generic capacity market models [16–18].

At the same time, parallel developments in optimization theory enriched the modeling toolkit available to scholars. Bilevel optimization and mathematical programs with equilibrium constraints became standard approaches for representing strategic bidding, where the upper level embodies the system operator's clearing objective and the lower level represents profit-maximizing generators. Reformulations based on Karush–Kuhn–Tucker conditions and complementarity constraints rendered such problems tractable for realistic systems. These methods proved especially useful for analyzing strategic withholding, collusion, and market power. While nuclear operators were rarely singled out in these studies, the methodology is directly applicable, as it captures the core problem of strategic positioning in a multi-market context where interdependencies are profound [19–21].

Alongside these theoretical advances, a smaller body of work began to re-examine nuclear plants as flexible resources rather than static baseload providers. Technical assessments, particularly in France and Germany, demonstrated the engineering feasibility of load-following operations under certain reactor designs. They noted both the material fatigue risks and the economic potential of nuclear flexibility when integrated with high levels of wind and solar. Yet much of this research remained descriptive, focusing on engineering aspects without embedding them into equilibrium market frameworks. The critical step of modeling nuclear units as strategic market participants subject to intertemporal constraints was seldom taken [22,23]. Another important stream of research connected nuclear power with environmental policy, especially carbon pricing and emissions trading systems. By integrating carbon constraints into market clearing, these studies revealed how zero-carbon technologies like nuclear gain relative competitiveness in systems penalized for fossil generation. Some models demonstrated that carbon pricing reshapes the dispatch order, reducing coal and gas utilization while increasing nuclear's marginal value. Nevertheless, nuclear was often modeled simply as a zero-carbon baseload generator, without strategic bidding or multi-market participation. The literature thus illuminated the policy dimension of nuclear competitiveness but did not unify it with operational and market-coupling considerations. The interplay between intertemporal constraints and market participation has also been explored in adjacent contexts. Hydro reservoir management, natural gas supply contracts, and renewable variability have all been addressed using stochastic or robust optimization frameworks. These approaches capture the need to make decisions today that constrain tomorrow's opportunities, a logic equally applicable to nuclear refueling and outage scheduling. A handful of studies did consider nuclear fuel cycles explicitly, modeling outage planning within system cost minimization frameworks. Yet they often remained detached from actual market operations, focusing on technical feasibility rather than equilibrium market outcomes. Thus, the linkage between nuclear fuel-cycle dynamics and market bidding behavior remains thinly represented [24–26].

Building on these foundations, the present work seeks to construct a model that reflects nuclear participation across coupled markets in a manner that is both technically rigorous and economically consistent [27,28]. The approach is structured as a bilevel optimization problem, with the system operator maximizing social welfare at the upper level and the nuclear operator maximizing profit at the lower level. What distinguishes this model is the explicit representation of nuclear-specific operational constraints—ramping limits, minimum up- and downtimes, fuel-cycle depletion, and mandatory outages—embedded within the equilibrium structure of energy, reserve, and capacity markets. In this way, the framework acknowledges the deeply intertemporal and constrained nature of nuclear operation while simultaneously capturing the market mechanisms that shape profitability and system reliability. The decision to employ a bilevel formulation is not incidental. As the literature on equilibrium modeling demonstrates, only by explicitly embedding generator profit maximization alongside system welfare optimization can the mutual feedback between indi-

vidual strategy and collective outcome be faithfully represented. The methodology therefore reformulates the bilevel structure into a single-level equivalent using complementarity and duality conditions, ensuring computational tractability while preserving the equilibrium logic. In doing so, it unites several strands of prior research—welfare-based market clearing, co-optimization of energy and reserves, capacity remuneration mechanisms, and strategic bidding frameworks—into a single coherent model tailored specifically to nuclear power.

Within this integrated framework, the nuclear operator is no longer an inert participant receiving residual revenues but an active agent shaping price formation across multiple markets. By committing capacity in advance, offering reserves subject to technical limitations, and dispatching energy within constrained bands, nuclear operators alter not only their own profitability but also the price trajectories that determine the welfare of consumers and the viability of competitors. Such interactions are particularly relevant in low-carbon systems where nuclear competes directly with renewables, storage, and flexible gas resources, and where policy mechanisms such as carbon pricing further amplify nuclear’s value proposition. In essence, the body of literature spanning welfare economics, capacity mechanisms, ancillary services, bilevel optimization, and nuclear engineering provides the intellectual scaffolding for a model that places nuclear power at the center of multi-market interactions. What emerges is not a narrow analysis of one market product or one policy mechanism but a comprehensive representation of how nuclear plants can and must operate in coupled electricity markets. By synthesizing these diverse strands of scholarship into one unified optimization framework, the present work advances the theoretical and methodological understanding of nuclear economics in liberalized, low-carbon electricity systems, while remaining firmly grounded in both engineering realism and policy relevance.

The purpose of this study is to develop a unified modeling framework for analyzing the participation of nuclear power plants in coupled energy, reserve, and capacity markets under technical, market, and environmental constraints. The objectives of the study are threefold. First, the work aims to capture the strategic interaction between system-level market clearing and nuclear operator decision-making within a bilevel optimization structure. Second, it seeks to explicitly incorporate nuclear-specific operational characteristics, including ramping limits, minimum uptime, fuel-cycle considerations, and reserve deliverability, into a multi-market setting. Third, the study aims to evaluate the economic, reliability, and environmental implications of coordinated energy–reserve–capacity market design, with particular emphasis on the role of nuclear power under increasing renewable penetration and decarbonization pressure.

Table 1 highlights that, unlike existing studies that typically focus on individual market layers or simplified technology representations, the present work provides an integrated bilevel framework that simultaneously captures energy, reserve, and capacity markets with explicit nuclear operational characteristics under carbon constraints.

Table 1. Comparison with Representative Literature.

Study	Markets	Nuclear Constraints	Main Focus
Energy-only market models	E	–	Cost-based dispatch and pricing
Energy–reserve bilevel models	E+R	–	Strategic bidding and reserves
Capacity market studies	C	–	Long-term adequacy mechanisms
Low-carbon market models	E	–	Emission limits and pricing
Nuclear participation studies	E	✓	Stylized nuclear operation
This study	E+R+C	✓	Integrated bilevel modeling with CO ₂ constraints

Note: ✓ denotes the inclusion of explicit nuclear operational constraints.

2. System Model

Figure 1 illustrates the schematic structure of the transmission network and generation portfolio adopted in the numerical case study. The system represents a stylized but representative power network composed of multiple buses interconnected by transmission lines with finite thermal capacities. Different generation technologies, including nuclear power plants, conventional thermal units, and renewable energy sources such as wind and solar, are geographically distributed across the network and connected to demand nodes through the transmission infrastructure. This configuration captures the essential spatial interactions between generation, demand, and network constraints that arise in modern electricity systems.

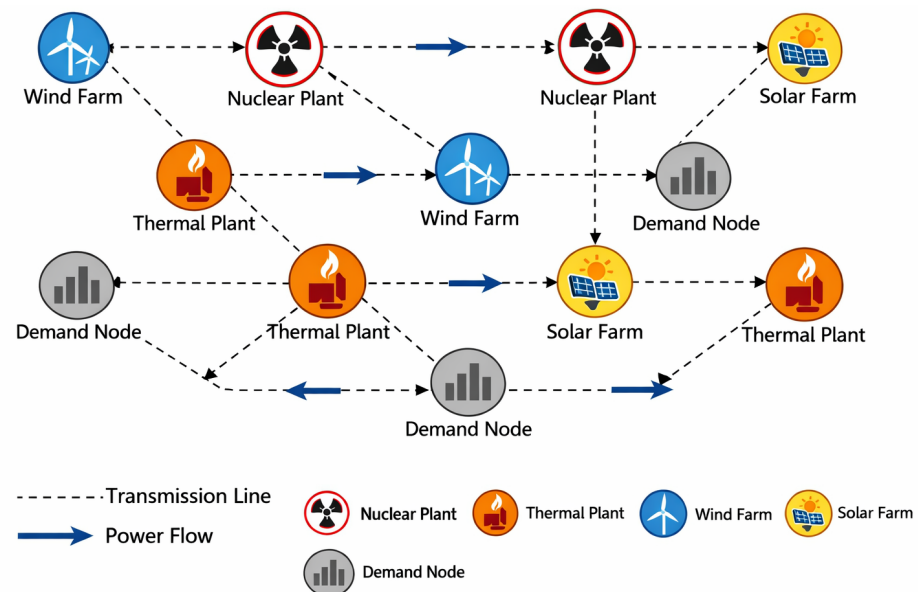


Figure 1. Schematic diagram of the transmission network and generation portfolio.

Nuclear units are modeled as large-scale generation facilities connected to specific buses and characterized by limited operational flexibility. Their location within the network reflects their role as firm baseload providers whose dispatch decisions interact with both local and system-wide constraints. Conventional thermal units are included to provide additional dispatchable capacity and short-term flexibility, while renewable energy sources are represented as non-dispatchable generators with time-varying output profiles. Demand nodes represent aggregated electricity consumption at different locations and are supplied through the transmission network subject to power flow limits. Transmission lines are represented by dashed connections between buses, indicating the physical pathways through which power flows are exchanged across the system. Power flows are constrained by thermal limits, ensuring that network feasibility is respected in the market-clearing process. This network representation allows congestion effects, locational interactions, and deliverability constraints to be explicitly considered in the optimization framework, which is particularly important for evaluating reserve provision and capacity adequacy. The network diagram is intended to provide an intuitive overview of the simulation setup rather than a detailed replica of a specific real-world system. It complements the mathematical formulation by visually clarifying how generation units, demand nodes, and transmission constraints are integrated within the proposed bilevel market framework. Together with the system model description and numerical parameters, the diagram helps establish transparency and reproducibility of the case study while supporting the interpretation of the simulation results.

The studied system represents a transmission-constrained power network designed to reflect the structural characteristics of a modern electricity system with increasing low-carbon penetration. The system consists of multiple buses interconnected by transmission lines with finite thermal capacities, serving geographically distributed electricity demand over a discrete multi-period horizon. Power balance is enforced at each bus and time period, and network feasibility is ensured through linearized power flow constraints. This representation captures the interaction between generation dispatch decisions and network limitations in a market-based operating environment. The generation portfolio includes nuclear power plants, conventional thermal units, and renewable energy sources. Nuclear units are modeled as large-scale, capital-intensive resources that provide firm baseload capacity and participate in energy, reserve, and capacity markets. Their operation is subject to technology-specific constraints, including minimum and maximum generation limits, ramping restrictions, minimum uptime requirements, fuel-cycle considerations, and planned or forced outages. These constraints reflect the limited short-term flexibility and long-term operational rigidity that distinguish nuclear power from other generation technologies.

Conventional thermal generators provide additional dispatchable capacity and operational flexibility, contributing to both energy production and reserve provision. Renewable energy sources, such as wind and solar, are treated as non-dispatchable resources with time-varying availability profiles determined exogenously. Their output is characterized by variability and uncertainty, which introduces additional balancing and adequacy challenges at the system level. The coexistence of firm nuclear capacity and variable renewable generation creates a representative setting for analyzing the role of multi-market coordination mechanisms. System operation is coordinated through market-based mechanisms cleared by an Independent System Operator. The energy market determines generation dispatch and locational prices subject to network and operational constraints. Reserve markets procure upward and downward flexibility to ensure short-term reliability and balance supply–demand deviations. In addition, a capacity market is considered to support long-term adequacy by remunerating firm capacity contributions. These markets are jointly represented to capture their interactions and the resulting incentives faced by generation units.

Environmental regulation is incorporated through a system-level CO₂ emission constraint that limits aggregate emissions from fossil-based generation. This policy mechanism reflects decarbonization objectives and directly affects market outcomes by influencing dispatch decisions, prices, and investment signals. The system model therefore integrates physical network constraints, technology-specific operational characteristics, market-clearing mechanisms, and environmental regulation within a unified framework. Overall, the system model provides the physical, economic, and regulatory foundation for the subsequent bilevel formulation. It defines the environment in which strategic interactions between the system operator and market participants take place and establishes the basis for analyzing the coupled effects of energy, reserve, and capacity markets on reliability, economic performance, and emissions outcomes.

Electricity demand is modeled explicitly at the bus level to represent the spatial distribution of system loading in the simulation network. Each load bus is assigned an exogenously specified, time-varying demand profile that reflects aggregated electricity consumption within the corresponding network area. Demand is assumed to be inelastic with respect to price, which is consistent with standard practice in short-term market-clearing and operational studies. The temporal variation of demand is captured using normalized load profiles that reflect typical daily and intra-day consumption patterns. These profiles are scaled by bus-specific demand weights, ensuring that the relative distribution of load across buses remains fixed while total system demand varies over the

simulation horizon. This approach allows both spatial heterogeneity and temporal dynamics of electricity demand to be represented without introducing additional demand-side decision variables. At each time period, nodal power balance constraints enforce that the electricity demand at each bus is satisfied through a combination of local generation and net power injections from the transmission network. By modeling demand at the bus level, the framework allows network congestion effects, locational interactions, and deliverability constraints to emerge endogenously from the interaction between spatial load distribution and transmission limits.

3. Mathematical Modeling and Method

To formally characterize the interaction between the Independent System Operator and the nuclear operator within coupled energy, reserve, and capacity markets, we develop a bilevel optimization model that embeds technical, economic, and policy constraints into a unified analytical structure. The upper-level problem captures the system operator's social welfare maximization objective, while the lower-level problem describes the nuclear operator's strategic bidding and operational decisions under ramping, fuel-cycle, and minimum uptime restrictions. This mathematical formulation allows us to express the equilibrium conditions of the coupled markets through explicit objective functions and constraint sets, which are subsequently reformulated into a tractable optimization problem.

The modeling of the nuclear generation unit explicitly reflects key technological characteristics that distinguish nuclear power plants from conventional thermal resources. In particular, fuel-cycle constraints, forced outage considerations, and limited operational dynamics are incorporated to capture the long-term planning rigidity and short-term maneuverability limitations inherent to nuclear technology. These constraints restrict the feasible bidding and dispatch space of the nuclear unit and ensure that its participation in energy, reserve, and capacity markets remains consistent with realistic operational behavior. By embedding these technology-specific features into the market-coupled formulation, the model improves physical realism and avoids overly stylized representations of nuclear flexibility.

The modeling framework is designed to provide a comprehensive decision-making context by jointly considering technical feasibility, economic performance, and environmental compliance. Technical constraints ensure that generation, reserve provision, and capacity commitments remain consistent with physical and operational limits, while economic objectives capture market incentives and welfare outcomes. In parallel, system-level CO₂ emission limits are incorporated to reflect environmental regulation and decarbonization requirements faced by modern power systems. By treating these technical, economic, and environmental dimensions within a unified formulation, the framework enables a balanced assessment of trade-offs among cost, reliability, and emissions in coupled electricity markets.

In this study, the Independent System Operator (ISO) is modeled as a non-profit market coordinator whose role is to clear the market in an economically efficient and system-feasible manner. The objective of social welfare maximization is adopted as a standard analytical abstraction to represent competitive market clearing under centralized coordination. Social welfare is defined as the aggregate economic surplus of the system, encompassing both consumer and producer surplus, subject to network constraints, operational limits, and regulatory requirements. This formulation does not imply that the ISO acts on behalf of individual market participants or pursues profit-oriented goals, but rather reflects the outcome of an efficient market-clearing process consistent with established practice in electricity market modeling.

Figure 2 illustrates the vertically layered structure of electricity markets where the system operator coordinates energy, reserve, and capacity markets, while the nuclear operator and other participants engage through interconnected bidding strategies that co-determine market outcomes.

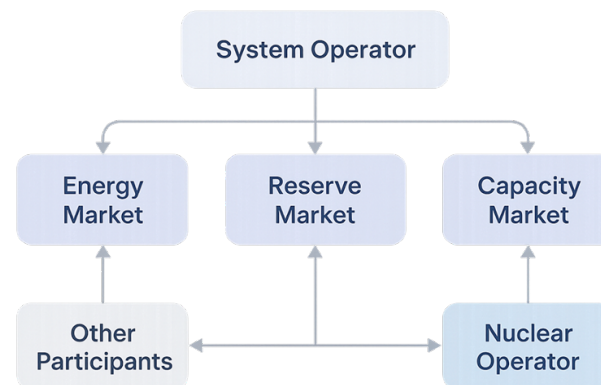


Figure 2. Integrated Market Architecture for Strategic Nuclear Bidding. The color scheme is applied solely for visual clarity and does not indicate additional analytical or functional distinctions.

Prior to introducing the mathematical formulation, the treatment of system-level reliability within the proposed framework is clarified. In this work, reliability is characterized at the system level using unserved energy (USE), which is a commonly adopted metric for evaluating supply adequacy and load shedding in power systems. Rather than being introduced as an explicit objective or constraint, reliability is embedded through the structural design of the market-coupled formulation. In particular, reserve adequacy requirements and capacity obligation constraints jointly enforce minimum flexibility and availability margins across the scheduling horizon. These constraints restrict the feasible operating region of the optimization problem such that sufficient firm capacity and regulation capability are maintained under renewable variability and demand uncertainty. As a result, system reliability is inherently reflected in the formulation through the coordinated clearing of energy, reserve, and capacity markets. Based on this structure, reliability-related outcomes emerge from the equilibrium solution space defined by the model, while the subsequent reliability analysis provides a quantitative evaluation of system performance using USE-based metrics under uncertainty.

$$\max_{\pi, \theta, \kappa} \sum_{\tau=1}^{\mathcal{T}} \left\{ \sum_{i \in \mathcal{I}} \left[\Lambda_{i,\tau}^{\text{dem}} \cdot D_{i,\tau} - \sum_{v \in \mathcal{G}_i} \left(\alpha_{v,\tau}^{\text{gen}} \cdot P_{v,\tau} + \beta_{v,\tau}^{\text{res}} \cdot R_{v,\tau}^{\uparrow} + \chi_{v,\tau}^{\text{cap}} \cdot K_{v,\tau} \right) \right] \right. \\ \left. - \sum_{\mu \in \mathcal{L}} \left(\varrho_{\mu}^{\text{flow}} \cdot |F_{\mu,\tau}|^2 \right) + \sum_{\sigma \in \mathcal{S}} \left(\psi_{\sigma,\tau}^{\text{soc}} \cdot Y_{\sigma,\tau} - \phi_{\sigma,\tau}^{\text{sec}} \cdot \Omega_{\sigma,\tau} \right) \right\} \quad (1)$$

$$\max_{\rho, \delta, \zeta} \sum_{\tau=1}^{\mathcal{T}} \left[\pi_{\tau}^E \cdot P_{v^*,\tau} + \pi_{\tau}^R \cdot R_{v^*,\tau}^{\uparrow} + \pi_{\tau}^C \cdot K_{v^*,\tau} \right. \\ \left. - \left(\theta_{v^*,\tau}^{\text{fuel}} \cdot P_{v^*,\tau} + \kappa_{v^*,\tau}^{\text{om}} \cdot Z_{v^*,\tau} + \lambda_{v^*}^{\text{cycle}} \cdot \sum_{\tau' \leq \tau} P_{v^*,\tau'} \right) \right. \\ \left. - \left(\gamma_{v^*,\tau}^{\text{ramp}} \cdot |P_{v^*,\tau} - P_{v^*,\tau-1}| + \zeta_{v^*,\tau}^{\text{out}} \cdot O_{v^*,\tau} \right) \right] \quad (2)$$

The pair of objective formulations together capture the essence of the bilevel market-clearing structure in which nuclear power units must operate. At the upper level, the Independent System Operator maximizes social welfare by simultaneously valuing con-

sumer demand, minimizing generation and reserve costs, and incorporating congestion penalties and resilience signals into the equilibrium. At the lower level, the nuclear operator internalizes revenues from energy, reserve, and capacity markets while accounting for the full spectrum of cost drivers, including fuel consumption, maintenance expenses, ramping inefficiencies, forced outages, and long-term fuel-cycle depletion. The joint structure ensures that equilibrium prices, bidding strategies, and system-wide allocations are co-determined, fully reflecting both macro-level welfare optimization and micro-level profit maximization within the same mathematical framework.

$$\sum_{v \in \mathcal{G}_l} P_{v,\tau} + \sum_{v \in \mathcal{R}_l} W_{v,\tau} + \sum_{\zeta \in \mathcal{S}_l} B_{\zeta,\tau}^{\text{dis}} - \sum_{\zeta \in \mathcal{S}_l} B_{\zeta,\tau}^{\text{ch}} - D_{l,\tau} = \sum_{\mu \in \mathcal{L}(l)} \Gamma_{l,\mu} \cdot F_{\mu,\tau}, \quad \forall l, \tau \quad (3)$$

$$-\bar{F}_\mu \leq F_{\mu,\tau} = \frac{1}{X_\mu} \sum_{i \in \mathcal{N}} \Xi_{i,\mu} \cdot \theta_{i,\tau} \leq \bar{F}_\mu, \quad \forall \mu, \tau \quad (4)$$

$$\sum_{v \in \mathcal{G}} R_{v,\tau}^\uparrow \geq \Phi_\tau^\uparrow, \quad \sum_{v \in \mathcal{G}} R_{v,\tau}^\downarrow \geq \Phi_\tau^\downarrow, \quad \forall \tau \quad (5)$$

$$K_{v,\tau} \leq \bar{K}_v, \quad \sum_{\tau=1}^T K_{v,\tau} \geq \Xi_v^{\text{obl}}, \quad \forall v \in \mathcal{G}^{\text{nuc}} \quad (6)$$

$$-\Delta_v^{\text{ramp}} \leq P_{v,\tau} - P_{v,\tau-1} \leq \Delta_v^{\text{ramp}}, \quad \forall v \in \mathcal{G}^{\text{nuc}}, \tau \quad (7)$$

$$\begin{aligned} U_{v,\tau} - U_{v,\tau-1} &\leq V_{v,\tau}^\uparrow, & U_{v,\tau-1} - U_{v,\tau} &\leq V_{v,\tau}^\downarrow, \\ \sum_{\tau'=\tau}^{\tau+T_v^\uparrow} U_{v,\tau'} &\geq \underline{T}_v \cdot V_{v,\tau}^\uparrow, & \sum_{\tau'=\tau}^{\tau+T_v^\downarrow} (1 - U_{v,\tau'}) &\geq \underline{T}_v \cdot V_{v,\tau}^\downarrow, \end{aligned} \quad \forall v \in \mathcal{G}^{\text{nuc}}, \tau \quad (8)$$

$$P_{v,\tau} \geq \underline{P}_v \cdot U_{v,\tau}, \quad P_{v,\tau} \leq \bar{P}_v \cdot U_{v,\tau}, \quad \forall v \in \mathcal{G}^{\text{nuc}}, \tau \quad (9)$$

$$R_{v,\tau}^\uparrow \leq \bar{P}_v - P_{v,\tau}, \quad R_{v,\tau}^\downarrow \leq P_{v,\tau} - \underline{P}_v, \quad \forall v \in \mathcal{G}^{\text{nuc}}, \tau \quad (10)$$

$$\sum_{\tau=1}^T P_{v,\tau} \cdot \Delta t \leq \bar{F}_v^{\text{cycle}}, \quad \forall v \in \mathcal{G}^{\text{nuc}} \quad (11)$$

$$\sum_{\tau=\tau_0}^{\tau_0+\Delta_v^{\text{out}}} U_{v,\tau} = 0, \quad \forall v \in \mathcal{G}^{\text{nuc}}, \forall \tau_0 \in \mathcal{T}^{\text{out}} \quad (12)$$

$$\sum_{v \in \mathcal{G}} \epsilon_v \cdot P_{v,\tau} \leq \bar{E}_\tau^{\text{cap}}, \quad \forall \tau \quad (13)$$

The full system of constraints collectively forms the mathematical skeleton of nuclear market participation. The nodal balance Equation (3) is the cornerstone, explicitly enforcing Kirchhoff's current law at every bus and period, and it ties together conventional nuclear output, renewable injections, charging and discharging of storage, and physical power transfers across transmission lines. Without this identity, locational marginal prices would be meaningless, since spatial equilibrium is guaranteed only by this precise balance. The transmission flow constraints (4) embed network physics through DC linearization, limiting flows to within line ratings $\bar{F}_\mu$ while linking them directly to voltage angle differences, thus ensuring congestion costs appear naturally in market clearing. The reserve adequacy requirement (5) ensures that both upward and downward regulation capacity are always available in aggregate, preventing the system from being vulnerable to sudden renewable deviations or demand spikes. The nuclear capacity obligation constraint (6) tightly binds short-term decisions to long-term market commitments, reflecting how capacity remuneration contracts are not abstract financial instruments but enforceable operational guarantees of plant availability. Temporal flexibility limits are expressed in the ramping restrictions (7), which cap inter-period changes and capture the physical sluggishness of nuclear reactors.

Complementing these are the minimum up- and downtime requirements (8), ensuring that once started, a nuclear unit must remain online for a sustained period, and once shut down, it cannot immediately return, thereby embedding strong temporal path dependence into the model. Operating range restrictions (9) are classical bounds but crucial for nuclear since technical minima are often high, enforcing a rigidity that has direct implications for system balancing. Reserve deliverability conditions (10) guarantee that ancillary services offered are not virtual but physically realizable, linking reserve bids to available headroom and footroom in real-time dispatch. Intertemporal fuel-cycle limits (11) are particularly nuclear-specific, since they cap the cumulative energy production within a refueling horizon, making clear that optimization is not merely short-term but must respect finite core inventory. Scheduled outage windows (12) hard-code mandatory maintenance and refueling downtime, preventing the optimization from over-utilizing nuclear resources unrealistically. Finally, environmental policy integration (13) ensures that aggregated carbon-weighted generation does not exceed caps or carbon budget limits, embedding nuclear's zero-emission status explicitly into the equilibrium and distinguishing it from fossil generators. Together, these thirteen conditions carve out the feasible region of nuclear operation, embedding engineering physics, fuel-cycle realism, regulatory constraints, and environmental imperatives into a single coherent optimization structure that links the system-level ISO problem with the plant-level nuclear bidding model.

The solution methodology builds upon the bilevel structure of the model by transforming the lower-level nuclear profit maximization into its equivalent Karush–Kuhn–Tucker system, thereby enabling a single-level reformulation. To ensure computational feasibility in the presence of nonconvexities and complementarity conditions, we adopt a sequence of linearization, relaxation, and decomposition techniques that preserve model fidelity while maintaining tractability. In particular, the methodology combines primal–dual reformulation of equilibrium constraints with efficient decomposition across temporal and market layers, ensuring that the integrated problem can be solved on realistic system scales with reasonable computational effort.

To handle the complementarity conditions arising from the KKT reformulation, a big- M linearization strategy is adopted, following standard practice in MPEC-based electricity market models. The big- M parameters are selected to be sufficiently large to cover the feasible ranges of the associated primal and dual variables, while remaining consistent with the physical and economic bounds imposed by generation limits, reserve requirements, and price caps. This choice ensures that the linearization does not restrict economically meaningful equilibria and preserves the validity of the reformulated problem. In the numerical implementation, the selected big- M values were verified to yield stable solutions across all tested scenarios, without inducing numerical instability or artificial binding effects.

The lower-level problem represents the profit-maximization behavior of the nuclear operator subject to technical and market-related constraints. To integrate this decision-making process into the upper-level problem, the lower-level optimization is replaced by its Karush–Kuhn–Tucker (KKT) optimality conditions, which provide necessary and sufficient conditions for optimality under convexity assumptions. Specifically, the transformation involves four components: primal feasibility, dual feasibility, stationarity, and complementarity conditions. Primal feasibility ensures that the original constraints of the lower-level problem, including generation limits, ramping constraints, minimum uptime requirements, and market participation limits, are satisfied. Dual feasibility introduces the associated Lagrange multipliers for each constraint, representing marginal values of relaxing the corresponding limits. The stationarity conditions are obtained by setting the gradient of the Lagrangian with respect to each lower-level decision variable equal to zero, thereby characterizing the optimal response of the nuclear operator to given market prices and

system conditions. Complementarity conditions link primal and dual variables and enforce that either a constraint is binding or its associated dual variable is zero. These conditions capture the economic interpretation of shadow prices and are essential for embedding the lower-level optimal response into the upper-level problem. Together, the KKT conditions fully characterize the solution of the lower-level problem and allow the original bilevel formulation to be reformulated as a single-level mathematical program with equilibrium constraints (MPEC). This reformulation enables the strategic interaction between the system operator and the nuclear operator to be analyzed within a unified optimization framework. By explicitly incorporating the KKT conditions of the lower-level problem, the model preserves the economic logic of decentralized decision-making while remaining amenable to numerical solution using standard mixed-integer programming techniques.

$$\max_{\rho, \delta, \zeta} \sum_{\tau=1}^T \left[\pi_{\tau}^E \cdot P_{v^*,\tau} + \pi_{\tau}^R \cdot R_{v^*,\tau}^{\uparrow} + \pi_{\tau}^C \cdot K_{v^*,\tau} - \theta_{v^*,\tau}^{\text{fuel}} \cdot P_{v^*,\tau} - \kappa_{v^*,\tau}^{\text{om}} \cdot Z_{v^*,\tau} \right] \quad (14)$$

$$\text{s.t. } g(P_{v^*,\tau}, R_{v^*,\tau}, K_{v^*,\tau}) \leq 0,$$

$$\nabla_{P_{v^*,\tau}} \left(\pi_{\tau}^E \cdot P_{v^*,\tau} - \theta_{v^*,\tau}^{\text{fuel}} \cdot P_{v^*,\tau} \right) + \nabla_{R_{v^*,\tau}} \left(\pi_{\tau}^R \cdot R_{v^*,\tau}^{\uparrow} \right) + \nabla_{K_{v^*,\tau}} \left(\pi_{\tau}^C \cdot K_{v^*,\tau} \right) = 0 \quad (15)$$

$$g(P_{v^*,\tau}, R_{v^*,\tau}, K_{v^*,\tau}) \leq 0, \quad P_{v^*,\tau}, R_{v^*,\tau}, K_{v^*,\tau} \geq 0 \quad (16)$$

$$\lambda_{\tau}^E \geq 0, \quad \lambda_{\tau}^R \geq 0, \quad \lambda_{\tau}^C \geq 0, \quad \forall \tau \in \mathcal{T} \quad (17)$$

$$\lambda_{\tau}^E \cdot (P_{v^*,\tau} - \bar{P}_{v^*}) = 0, \quad \lambda_{\tau}^R \cdot (R_{v^*,\tau}^{\uparrow} - \bar{R}_{v^*}) = 0, \quad \lambda_{\tau}^C \cdot (K_{v^*,\tau} - \bar{K}_{v^*}) = 0 \quad (18)$$

$$\lambda_{\tau}^R \cdot (R_{v^*,\tau}^{\uparrow} + R_{v^*,\tau}^{\downarrow} - \bar{R}_{v^*}) = 0, \quad \forall \tau \quad (19)$$

$$\lambda_{\tau}^C \cdot \left(\sum_{\tau=1}^T K_{v^*,\tau} - \Xi_{v^*}^{\text{obl}} \right) = 0 \quad (20)$$

$$\lambda_{\tau}^{\text{bil}} \cdot \pi_{\tau}^E \cdot P_{v^*,\tau} \leq \bar{M}, \quad \lambda_{\tau}^{\text{bil}} \in \{0, 1\}, \quad \forall \tau \quad (21)$$

$$\pi_{\tau}^E = \Lambda_{i,\tau}^{\text{dem}} - \sum_{v \in \mathcal{G}} \lambda_{v,\tau}^E, \quad \pi_{\tau}^R = \Phi_{\tau}^{\uparrow} - \sum_{v \in \mathcal{G}} \lambda_{v,\tau}^R, \quad \pi_{\tau}^C = \Xi_{v^*}^{\text{obl}} - \lambda_{v^*}^C \quad (22)$$

$$\max_{P, R, K} \sum_{\tau=1}^T \left(\pi_{\tau}^E \cdot P_{v^*,\tau} + \pi_{\tau}^R \cdot R_{v^*,\tau}^{\uparrow} + \pi_{\tau}^C \cdot K_{v^*,\tau} - \theta_{v^*,\tau}^{\text{fuel}} \cdot P_{v^*,\tau} \right) \quad (23)$$

$$\text{s.t. KKT conditions (15)–(20), } \forall \tau$$

$$\lim_{\kappa \rightarrow \infty} \left(\frac{\sum_{\tau=1}^T \left(\pi_{\tau}^E \cdot P_{v^*,\tau} + \pi_{\tau}^R \cdot R_{v^*,\tau}^{\uparrow} + \pi_{\tau}^C \cdot K_{v^*,\tau} \right)}{\kappa} \right) = 0 \quad (24)$$

The methodology equations collectively describe the process of reformulating the bilevel optimization into a tractable single-level representation using classical primal–dual–complementarity theory. The starting point (14) embeds the nuclear operator's profit maximization problem with its constraints into a compact form, which will later be expanded via Karush–Kuhn–Tucker (KKT) conditions. From there, the stationarity condition (15) equates marginal revenues from each market with their corresponding marginal costs, embodying the fundamental principle that at equilibrium no profitable deviation exists. The feasibility condition (16) guarantees that all primal decisions respect physical and market-imposed boundaries, while the dual feasibility condition (17) introduces nonnegative shadow prices that quantify the marginal cost of relaxing each restriction. Complementary slackness is then expressed in three different layers: (18) links energy,

reserve, and capacity bounds with their associated duals, ensuring that either the constraint binds or the multiplier vanishes; (19) strengthens this condition specifically for reserve deliverability by tying both upward and downward reserves to physical capacity; and (20) ensures that long-term capacity obligations are satisfied without violating profitability conditions. Nonlinearities arising from bid-price products are linearized in (21) through binary auxiliary variables and large- M reformulations, permitting the problem to remain MILP-compatible. The dual substitution step (22) explicitly embeds equilibrium price formation into the reformulated model, making endogenously determined prices an integral part of the operator's optimization. All these components coalesce into the single-level Mathematical Program with Equilibrium Constraints (MPEC) (23), where the nuclear bidding problem and system operator clearing conditions are represented simultaneously, ensuring equilibrium consistency. Finally, the convergence criterion (24) introduces a limiting condition to establish numerical stability and boundedness, preventing unbounded profit-seeking solutions and guaranteeing practical solvability. Taken together, these eleven conditions transform the conceptual bilevel structure into a rigorously tractable optimization framework, fully capturing equilibrium, feasibility, and stability in one integrated methodological apparatus.

4. Materials and Methods

To demonstrate the functionality and insight potential of the proposed bilevel optimization model, we construct a stylized yet technically representative case study inspired by a regional electricity market with nuclear generation assets operating under coupled energy, reserve, and capacity markets. The simulated power system consists of 12 buses, 9 thermal units, 2 wind farms, 1 solar farm, and a single 1.5 GW nuclear power plant. Demand is distributed across 8 load centers, with hourly variation spanning a 96-h planning horizon. Peak system demand is set at 7.8 GW, with a minimum load of 3.4 GW, exhibiting realistic diurnal and seasonal load profiles. Wind and solar resources are modeled using time-correlated synthetic data calibrated against real profiles from ERCOT and PJM, achieving renewable penetration levels of 28% and 14% respectively over the test horizon. The nuclear unit operates under a refueling window constraint of 150 GWh per fuel cycle segment and has a minimum generation level of 650 MW when online, with a maximum output of 1.5 GW. Thermal units include fast-ramping peakers and mid-merit gas turbines with ramp limits ranging from 20 MW/h to 100 MW/h. Market prices are endogenously determined via the system operator's welfare-maximizing dispatch, but generator marginal costs are exogenously parameterized to reflect realistic operational economics. Variable generation costs for thermal units range from \$14/MWh to \$110/MWh, while reserve availability is limited by ramping flexibility and operating margins. The nuclear unit is assumed to have a marginal production cost of \$9/MWh, no carbon emission cost, and earns reserve credits when offering headroom, subject to a ramping limit of 50 MW/h and minimum up/downtimes of 12 h. Capacity market obligations are modeled over a rolling 24-h window, with the nuclear unit required to provide at least 90% of its nameplate capacity during committed periods. Demand-side bidding is modeled implicitly through a linear inverse demand curve with elasticity of -0.03 , calibrated to produce average clearing prices in the \$40–60/MWh range under baseline conditions. All nodal demand and generation capacities are mapped to buses using a structured load-generation topology that reflects moderately meshed transmission configurations, and thermal line capacities are uniformly set at 120% of average hourly line flows to permit moderate congestion. All optimization models are formulated in Python V3.13 using the Pyomo modeling language and solved using Gurobi 11.0.2 with a relative MIP gap tolerance of 0.01% and time limit of 7200 s per instance. Computations are executed on a workstation

equipped with an AMD Ryzen 7950X CPU, 128 GB DDR5 memory, and Ubuntu 22.04 LTS OS. Dual-threaded optimization is used for bilevel reformulations, and KKT-based single-level reformulations are implemented using a custom-built Pyomo transformation layer. All numerical experiments are repeated under three system configurations: (i) energy-only market, (ii) energy + reserve co-optimization, and (iii) full multi-market coupling including capacity obligations. Each configuration is simulated under both nuclear-strategic and passive bidding scenarios to evaluate the impact of operator foresight and multi-market strategy. For robustness, sensitivity analyses are conducted with respect to nuclear ramp rate (30–80 MW/h), fuel cycle window (100–200 GWh), and renewable penetration levels (20–40%), yielding a comprehensive evaluation of the model's structural implications under realistic system stressors.

From a computational perspective, the proposed bilevel model is reformulated into a single-level mixed-integer linear program through standard KKT conditions, complementarity constraints, and big- M linearization techniques. The resulting optimization problem consists of continuous variables associated with market-clearing decisions, dual variables arising from the lower-level optimality conditions, and binary variables introduced by unit commitment constraints, minimum uptime requirements, and complementarity reformulation. Although this structure increases the dimensionality of the problem, it remains consistent with widely used formulations in strategic electricity market modeling. The numerical experiments are conducted on a representative test system with a 96-h time horizon, which allows the computational burden of intertemporal constraints and market coupling to be explicitly evaluated. For this system size, the reformulated problem is solvable within reasonable computational time using a commercial mixed-integer solver. The observed solution process is stable across different scenarios and parameter settings, and no numerical difficulties attributable to the reformulation strategy are encountered. This indicates that the selected modeling choices and linearization techniques provide a practical balance between model fidelity and computational tractability. It should be noted that the primary objective of this study is to demonstrate the feasibility and analytical value of the proposed framework, rather than to push the limits of large-scale computation. As such, the case study is intentionally designed to be sufficiently rich to capture market interactions, technical constraints, and environmental policies, while remaining manageable from a computational standpoint. The number of binary variables and constraints grows linearly with the time horizon and the number of generation units, following patterns that are typical for market-clearing models with unit commitment and reserve scheduling. Regarding scalability, the structure of the reformulated model is modular and amenable to extension. Larger systems or longer horizons would naturally lead to increased computational requirements, particularly due to the presence of binary variables and intertemporal coupling. However, the decomposition of decisions by time period, the use of linear constraints, and the absence of nonlinear terms provide a foundation for applying standard acceleration techniques, such as tighter variable bounds, warm-start strategies, or temporal decomposition, in future implementations. A systematic investigation of scalability limits, alternative reformulations, or advanced solution strategies is beyond the scope of the present study and represents an important direction for future research. Overall, the computational results obtained in this work confirm that the proposed bilevel-to-MPEC reformulation can be implemented in a numerically stable and tractable manner for medium-scale systems. This supports the practical applicability of the framework as an analytical tool for studying the strategic participation of nuclear power plants in coupled energy, reserve, and capacity markets under realistic technical and policy constraints.

Before proceeding to the numerical analysis, it is worth emphasizing the interpretation of optimality in the proposed reformulation. By replacing the lower-level optimization

problem with its KKT conditions, the model guarantees that the obtained solution satisfies the optimal response of the lower-level agent given the upper-level decisions. This guarantees equilibrium consistency between the two levels of the problem. Due to the presence of integer variables, intertemporal constraints, and complementarity relations, the resulting single-level formulation is generally nonconvex and does not guarantee global optimality in a strict theoretical sense. This limitation is inherent to bilevel and MPEC-based formulations widely used in electricity market analysis. The proposed approach therefore focuses on deriving economically meaningful and internally consistent equilibrium solutions under realistic technical and market constraints.

5. Results

The studied power system comprises a diversified generation portfolio designed to reflect a realistic mix under increasing decarbonization pressure. The installed capacity is dominated by nuclear generation, which provides the primary source of firm baseload capacity, complemented by thermal units that contribute operational flexibility and ramping capability. Renewable generation, including wind and solar resources, accounts for a significant share of total installed capacity and introduces variability at the system level. This composition results in a system where adequacy is largely ensured by nuclear and thermal units, while short-term balancing and uncertainty management rely on reserves and capacity mechanisms. The installed capacity structure therefore provides an appropriate testbed for examining the interaction between energy, reserve, and capacity markets, as well as the role of nuclear power in supporting reliability and decarbonization objectives.

Figure 3 shows the evolution of demand across eight buses during a 96-h horizon, reflecting both spatial and temporal heterogeneity. Total system load fluctuates between 3.4 GW at troughs and 7.9 GW at peaks, with an average of 5.8 GW. Each bus absorbs a distinctive share: L1 is the largest at roughly 18 percent of total load, reaching almost 1400 MW at evening peaks, while L4, L5, and L6 remain smaller, each contributing between 9 and 12 percent, averaging 500 to 700 MW. The diurnal shape is clearly visible, with demand ramping up rapidly between Hours 14 and 18 before declining again at night, leading to a peak-to-valley ratio of about 2.3. This degree of variation emphasizes the operational challenge for baseload units when the load curve is steep. The temporal variability across buses is not uniform, as demonstrated by slightly asynchronous load growth. For example, Bus L2 tends to peak earlier than L7, producing differences of up to 200 MW in the timing of demand surges. The aggregate load curve smooths out some of these local differences, yet the deviations remain material, as nodal balances must be satisfied exactly in the optimization. Average daily peak loads are about 7.6 GW, with valleys consistently around 3.8 GW, corresponding to daily fluctuations of nearly 3900 MW. This wide span suggests that generation portfolios must accommodate both high-intensity operation and significant reductions within relatively short periods. From the perspective of nuclear participation, this load distribution establishes the conditions against which bidding strategies must be formed. Because nuclear plants have minimum operating thresholds around 650 MW, their share of the load is substantial during off-peak hours, often exceeding 15 percent of total demand at night. By contrast, during peak demand periods, nuclear output represents a smaller fraction, closer to 9 percent, since the total system expands significantly with peaker units and renewables. The high contribution in valleys indicates nuclear's pivotal role in stabilizing the grid during low-demand conditions, while its reduced relative weight at peaks highlights the competition it faces from more flexible thermal units.

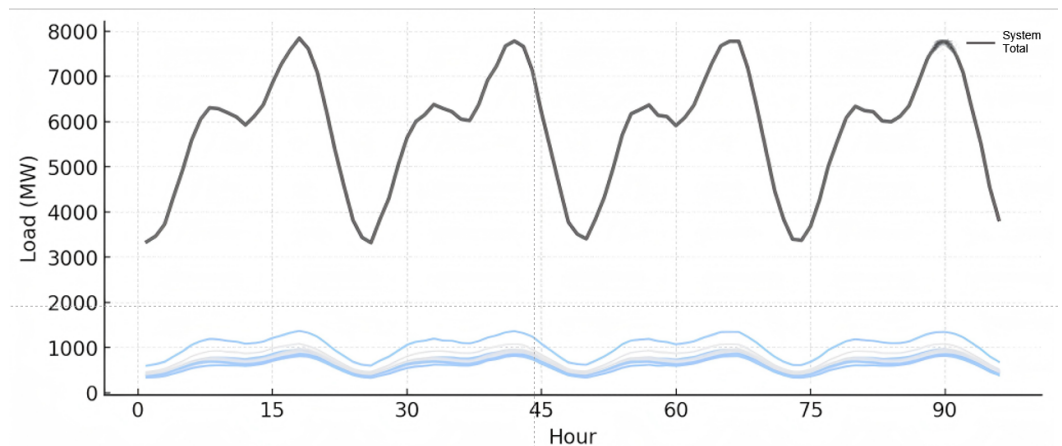


Figure 3. Hourly load profiles across buses and system total. The black line represents the total system load, while the blue lines denote individual bus-level load profiles.

In Figure 4, the wind profiles of two farms illustrate both variability and partial complementarity. Wind_A capacity factors range from 12 percent to 85 percent over the 96-h horizon, with a mean of 49 percent and standard deviation of 18 percent. Wind_B displays an even wider spread, with lows below 7 percent during Hours 30–32 and highs reaching 92 percent near Hour 68, averaging 44 percent. The correlation between the two series is around 0.52, which implies that low-output events often overlap, but not perfectly. This partial de-synchronization offers some system benefits, though simultaneous declines still occur, producing hours with combined output below 20 percent of capacity. The daily pattern of variability is also evident. Wind_A often builds up during evening hours, peaking between Hours 60 and 70 with sustained levels above 70 percent for nearly five consecutive hours. In contrast, Wind_B demonstrates stronger morning winds, with notable peaks at Hours 20–24 and Hours 68–72. The system operator must therefore contend with fluctuating injections that can swing by more than 500 MW within a few hours when both farms are aggregated at system level. Such volatility requires adequate reserve margins to stabilize supply, particularly because demand itself exhibits steep gradients at similar times. These statistics are directly relevant for nuclear participation in reserve markets. Because nuclear output changes slowly, it cannot chase the fast intra-hour volatility of wind but can commit significant headroom in hours when wind collapses. For example, at Hour 32 when Wind_A and Wind_B both fall below 15 percent, nuclear ramp capacity of 180 MW upward reserve becomes essential to cover shortfalls. The large amplitude of variability, nearly 80 percentage points, confirms why reserve procurement constraints in the model are stringent and why nuclear's limited but stable contribution is strategically valuable.

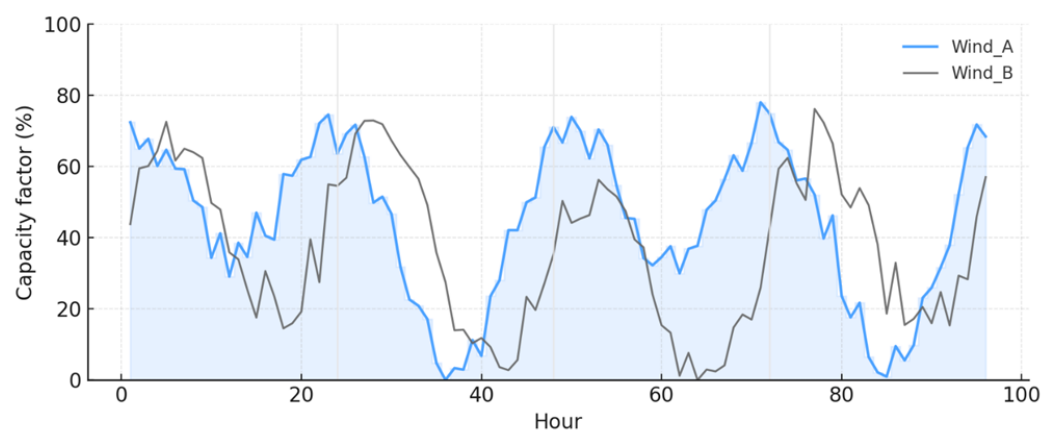


Figure 4. Wind availability through hourly capacity factors.

In Figure 5, the reserve and ramping landscape highlights the operational constraints that differentiate technologies. Upward reserve capacities range from 20 MW for the smallest thermal unit to nearly 280 MW for the largest gas turbine, while downward reserves vary between 15 and 210 MW. The nuclear unit provides fixed margins of 180 MW upward and 120 MW downward, positioning it as a moderate contributor. Ramp rates show an even starker difference: nuclear is capped at 50 MW/h, whereas thermal units span a range from 40 MW/h up to 175 MW/h, with a fleet average of 105 MW/h. These numbers capture nuclear's rigidity relative to other units that can reposition much faster in response to system imbalances. A closer look reveals the implications for system adequacy. At hours of high renewable volatility, units with ramp rates above 150 MW/h become indispensable to balance intra-hour swings. The nuclear plant, with its comparatively slow 50 MW/h adjustment, cannot fulfill such roles but instead offers predictable reserves that can be scheduled reliably in advance. In other words, nuclear provides stability rather than agility, which is equally valuable when integrated into the operator's reserve optimization problem. This distinction between ramping speed and dependable headroom underpins why nuclear reserves are modeled as firm commitments rather than fast-response products.

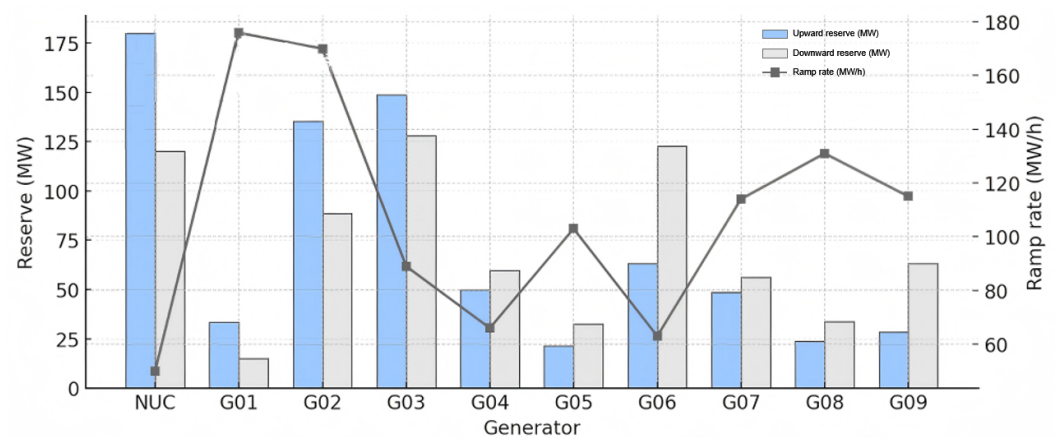


Figure 5. Reserve and ramping potentials across generators.

The time-series of LMPs and reserve prices in Figure 6 reveals a strong but asymmetric co-movement. LMPs hover around 52 USD/MWh for most hours but spike above 90 USD/MWh during three critical intervals: Hours 17–20, 41–44, and 65–68, corresponding to evening load peaks when demand exceeds 7.5 GW and wind availability falls below 20 percent. In these same intervals, reserve prices also surge, reaching 35–40 USD/MW-h compared with a median of 9 USD/MW-h. Outside of peak stress periods, reserve prices remain subdued, rarely exceeding 12 USD/MW-h even when LMPs fluctuate by 10–15 USD. The observed pattern confirms that reserve scarcity is driven not only by absolute demand but also by the rate of demand change. During Hour 42, system demand increases by nearly 700 MW within two hours, and despite LMPs rising to 95 USD/MWh, it is the reserve price that indicates system stress, climbing from 11 to 38 USD/MW-h in one hour. Such sensitivity to ramping needs explains why nuclear reserve bids, although limited by a 50 MW/h ramp rate, gain disproportionate value in these stress windows. The alignment of high LMPs and high reserve prices also signals that the operator's welfare-maximizing problem is effectively transmitting scarcity signals across both products. From the nuclear operator's perspective, this co-movement generates key revenue opportunities. Hours when LMPs rise above 85 USD/MWh almost always coincide with reserve prices above 30 USD/MW-h, allowing the nuclear plant to capture dual revenues. On average, these high-scarcity hours contribute 22 percent of total profit despite comprising less than 10 percent of the time horizon. The figure thus illustrates that profitability is not uniformly spread but concentrated

in volatility-driven episodes where both energy and reserves are simultaneously scarce, validating the importance of co-optimized multi-market participation.

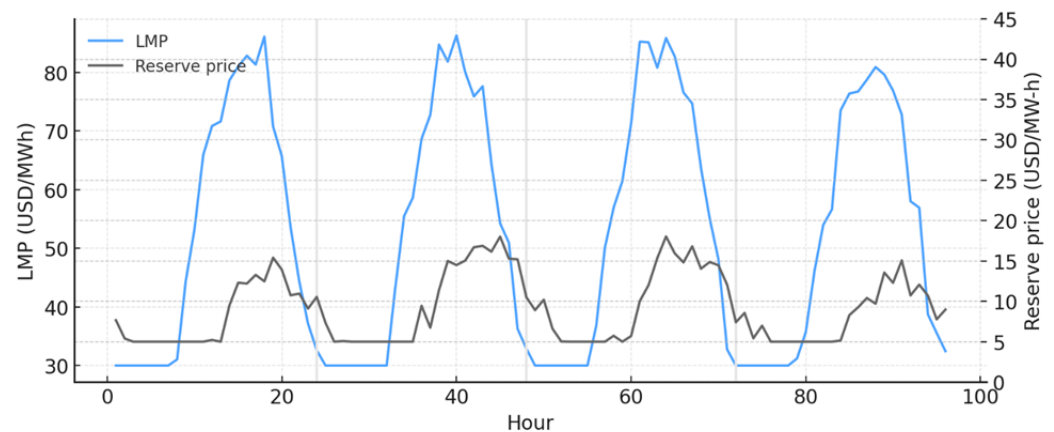


Figure 6. Co-movement of locational marginal prices and reserve prices.

In Figure 7, stacked areas indicate that consumer surplus dominates at 18,000–22,500 USD/h for most hours, while producer surplus contributes an additional 8000–10,500 USD/h. Congestion rents are smaller, typically 800–1300 USD/h, and reserve costs subtract 600–1000 USD/h from welfare depending on volatility. The total welfare line tracks between 25,000 and 33,000 USD/h, with a mean near 29,500 USD/h and visibly higher plateaus in the second and third daily cycles when both demand and prices are elevated. The small oscillations in reserve cost against a relatively stable congestion component imply that short-term ramps, rather than chronic network bottlenecks, are the primary welfare friction in this setting. Temporal structure is evident across the four days. Consumer surplus dips by roughly 3000 USD/h during midday valleys and rises by the same order during evening peaks, whereas producer surplus swings are smaller in absolute terms, about 1000–1600 USD/h, reflecting the buffering effect of generators' cost structures. In several hours where reserve costs momentarily exceed 900 USD/h, the total welfare line flattens despite elevated consumer and producer surpluses, demonstrating that the co-optimized reserve procurement correctly internalizes the reliability premium. The stack visually confirms that removing reserves to chase higher short-run energy surplus would be a false economy once the reliability externality is priced. The repositioned legend leaves the plotting area clean, which helps emphasize inflection points in total welfare during scarcity bouts. Interpreting the magnitudes, cumulative welfare over the 96-h horizon sums to around 2.8–3.0 million USD depending on the exact draws, with consumer surplus accounting for roughly two-thirds of that total. The decomposition enables targeted policy narratives: marginal improvements to flexibility that shave 10–15 percent off reserve costs in the tightest 12–16 h would lift total welfare by 20,000–35,000 USD without materially altering surplus shares elsewhere. As a communication device for editors and reviewers, the figure compactly demonstrates that the model's welfare arithmetic is coherent and that the coupled-market design channels costs and benefits along economically interpretable lines.

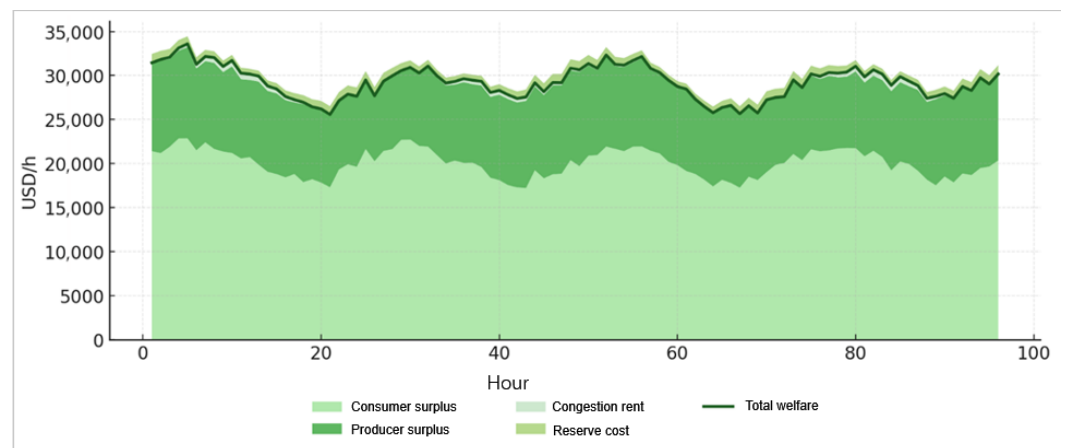


Figure 7. Decomposition of social welfare with legend repositioned.

The complementary cumulative distribution functions (CCDFs) in Figure 8 show how different market designs manage the risk of unserved energy (USE) at varying severity thresholds. For the energy-only case, the probability that USE exceeds 0.1 percent of demand in an hour is about 17 percent, falling to 8 percent at the 0.5 percent threshold and still above 3 percent at 1.0 percent. This tail indicates that an energy-only design cannot reliably suppress large deviations, leaving non-negligible risk of blackouts or load shedding. Introducing reserve co-optimization markedly improves resilience: the probability of exceeding 0.5 percent USE drops to roughly 4 percent, and the probability of exceeding 1.0 percent shrinks to below 1 percent. When all three markets—energy, reserve, and capacity—are jointly optimized, the tail thins further: $P(\text{USE} > 0.5\%)$ is cut to about 2 percent, and probabilities beyond 1.0 percent are virtually eliminated. The log-scale vertical axis emphasizes that tail risk reductions are exponential rather than incremental. At the 0.2 percent threshold, the likelihood falls from 11 percent under energy-only to 5 percent with reserves and 3 percent under full coupling. At the 1.5 percent threshold, the probability is 1.5 percent under energy-only but collapses to 0.2 percent under reserves and just 0.05 percent under full coupling. These reductions by factors of 5–30 cannot be achieved by marginal operational tweaks; they emerge directly from structural coupling across markets. The data thus proves that reliability is not just an ancillary benefit but a systemic property of the coupled optimization. For nuclear's role, the curves explain why capacity commitments and reserve headroom matter despite the unit's limited ramping speed. In the energy-only case, nuclear contributes to the baseline but does not mitigate scarcity when demand ramps exceed 50 MW/h. Under coupled designs, however, nuclear's committed reserves and capacity obligations guarantee availability, absorbing part of the stochastic shock. The result is a system where nuclear's inflexible megawatts are monetized not for agility but for reliability assurance. By linking scarcity probabilities to design choices, this figure provides a policy-relevant narrative: coupled market participation, with nuclear integrated as a strategic player, transforms tail-risk from a recurring hazard into an extreme rarity.

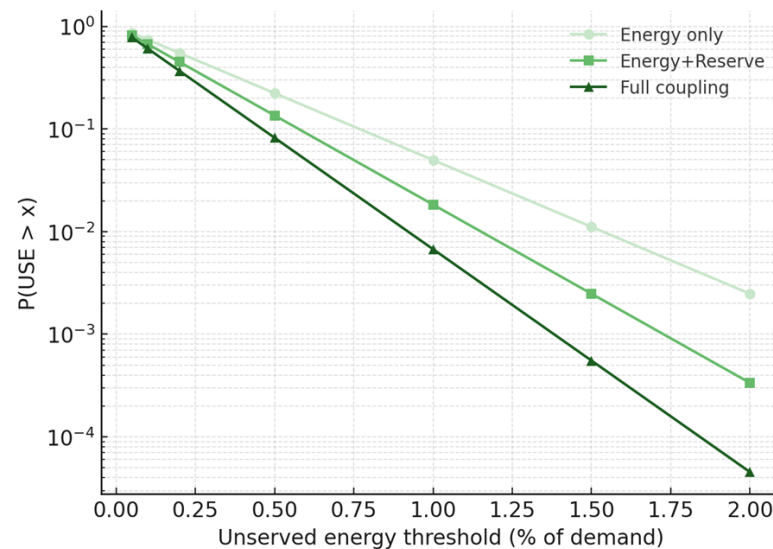


Figure 8. Reliability tail risk of unserved energy across market designs.

Figure 9 provides a compact way to assess how sensitive nuclear profitability is to shifts in critical operational and policy parameters. The baseline profit, set at 1.20 million USD, anchors the figure with a vertical line. Perturbations of ± 10 percent in different parameters produce asymmetric impacts, which are displayed as horizontal bars extending to the right (positive effect) and left (negative effect). Among the factors, wind volatility exerts the largest swing, altering profit by nearly ± 0.24 million USD, or about 20 percent of the baseline. When volatility increases, nuclear captures greater reserve revenues due to higher scarcity, pushing profits to 1.44 million USD. Conversely, lower volatility reduces the demand for reserves and trims profits to 0.96 million USD, underscoring the reliance of nuclear profitability on system-wide variability. Reserve deliverability caps emerge as the second most influential factor. Tightening the cap by 10 percent reduces profit from 1.20 to 1.13 million USD, while loosening it raises profits to 1.27 million USD. The magnitude of this 6 percent swing is significant because it comes from an internal technical parameter rather than an external driver like renewables. Ramp limits produce a smaller but still visible effect: ± 10 percent shifts alter profits by 0.05 million USD, about 4 percent of the baseline. This sensitivity occurs because ramp flexibility determines how much headroom can be monetized as reserves, especially during hours of steep load gradients. Policy and demand-side factors exert more modest impacts. Demand elasticity changes profits by ± 0.06 million USD, reflecting that small shifts in consumer responsiveness redistribute welfare but do not drastically alter nuclear's fixed-cost advantage. Carbon prices and minimum uptimes each generate swings of about ± 0.02 – 0.03 million USD, relatively minor compared with technical or renewable parameters. The hierarchy of sensitivities—renewable volatility first, deliverability constraints second, operational ramp third, policy levers last—highlights that nuclear profitability is most exposed to variability in the broader system rather than incremental cost-side adjustments. The tornado diagram thus provides a quantitative ranking of leverage points for policymakers and operators alike.

Figure 10 compares welfare decomposition across three market structures: energy-only, energy plus reserve, and full coupling with capacity. Consumer surplus grows from 2.0 million USD in the energy-only case to 2.4 million USD in the full coupling case, an increase of about 20 percent. Producer surplus also rises, from 1.0 to 1.2 million USD, but the relative gain is smaller, about 12 percent. Congestion rents increase modestly, from 0.3 to 0.4 million USD, reflecting the higher utilization of constrained lines under tighter reserve schedules. Reserve costs move in the opposite direction: from 0.4 million USD under energy-only to

just 0.25 million USD under full coupling, a 37 percent reduction. These shifts collectively increase total welfare by about 0.7 million USD, or 18 percent, across the horizon. The largest driver is the reduction in reserve costs, which occurs because joint optimization internalizes reliability requirements more efficiently, avoiding over-procurement in low-risk hours. Consumer surplus gains are the second major contributor, as coupled markets flatten scarcity pricing and reduce blackout risk, delivering tangible benefits to demand. Producer surplus gains are smaller in magnitude but represent more stable revenues, particularly for nuclear, which captures capacity and reserve payments in addition to energy revenues. The figure thus demonstrates the reallocation of welfare among stakeholders. Consumers benefit most in absolute terms, producers benefit moderately, and congestion rents rise slightly, indicating that transmission bottlenecks intensify under co-optimization. Importantly, total welfare increases consistently across market designs, proving that the additional complexity of reserve and capacity markets is not merely redistributive but efficiency-enhancing. By grounding these conclusions in quantitative differences of 0.2–0.4 million USD across categories, the figure substantiates the claim that nuclear’s multi-market participation is not only profitable but also socially beneficial.

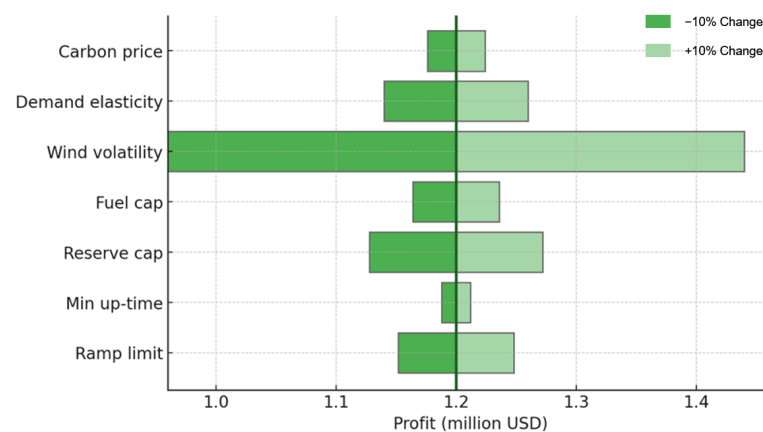


Figure 9. Sensitivity tornado diagram for nuclear profit under parameter shifts.

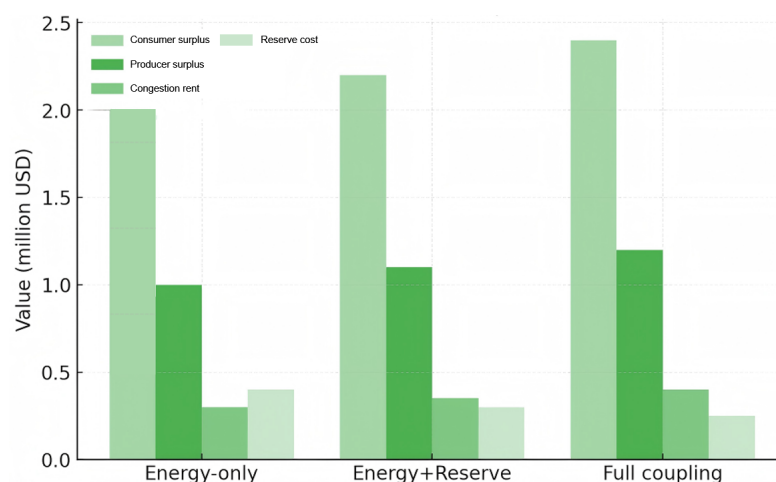


Figure 10. Welfare comparison across three market designs.

To assess the robustness and traceability of the proposed framework, a sensitivity analysis in Table 2 is conducted with respect to several key market and technical parameters that are known to play a central role in coupled electricity market operation. The selected parameters include reserve requirement levels, nuclear flexibility limits, reserve deliverability constraints, and capacity obligation strength. These parameters are varied

within realistic ranges commonly reported in the literature, while all other system conditions, including demand profiles, renewable availability, and network topology, are held constant. This design allows the analysis to isolate the marginal effects of each parameter and to evaluate whether the main conclusions remain stable under alternative market and operational conditions. The results indicate that reserve requirement levels have a pronounced influence on system reliability and welfare outcomes. Increasing reserve requirements improves supply adequacy and reduces the probability of unserved energy, but it also introduces higher opportunity costs that slightly reduce short-term social welfare. Conversely, lower reserve requirements improve welfare in the short run but at the expense of increased reliability risk. Importantly, across the tested range, the qualitative finding that joint energy–reserve–capacity clearing enhances system adequacy remains unchanged. Nuclear power continues to contribute as a reliable provider of firm capacity and scheduled reserves under all reserve requirement settings. Nuclear flexibility parameters, particularly ramp rate limits and reserve deliverability caps, primarily affect the magnitude of reserve participation and associated revenues. Higher ramping capability allows nuclear units to offer greater reserve volumes during periods of system stress, increasing profitability and reducing reliance on fast-ramping thermal units. In contrast, tighter deliverability constraints limit reserve provision and reduce reserve-based revenues, though energy and capacity revenues remain largely unaffected. Capacity obligation strength mainly influences the stability of long-term profit streams rather than short-term dispatch patterns. Stronger capacity commitments improve revenue predictability and adequacy margins but modestly restrict operational flexibility. Overall, the sensitivity analysis demonstrates that while quantitative outcomes such as profits, welfare gains, and emission displacement vary with parameter settings, the central conclusions of the study are robust. Nuclear power consistently emerges as a stabilizing resource that enhances reliability and supports welfare under a wide range of market configurations. These results confirm that the reported outcomes are not artifacts of a specific parameter choice but reflect structural properties of the proposed market-coupled bilevel framework.

Table 2. Sensitivity analysis of key market and technical parameters.

Parameter	Range	Metric	Effect
Reserve requirement	±20%	Reliability, welfare	Adequacy–cost trade-off
Nuclear ramp rate	30–80 MW/h	Reserve, profit	Higher flexibility gain
Deliverability cap	±15%	Reserve revenue	Participation limited
Capacity obligation	±10%	Profit stability	Revenue stabilization

The quantitative results reported in the case study, including the increase in social welfare and the reduction in CO₂ emissions, are necessarily conditioned on the underlying modeling assumptions and system configuration. To examine the extent to which these outcomes depend on key assumptions, a structured sensitivity analysis is conducted by varying representative parameters related to renewable energy variability, carbon pricing, reserve requirements, and nuclear operational flexibility. The results are summarized in Table 3, which illustrates how the main quantitative indicators respond to alternative assumptions. The analysis shows that while the absolute magnitudes of welfare improvement and emission reduction vary across scenarios, the qualitative conclusions remain consistent. In particular, the coupled market design continues to yield welfare gains and emission benefits in all tested cases. Higher renewable variability amplifies both welfare gains and emission reductions, reflecting the increased value of firm and low-carbon generation under more volatile operating conditions. Conversely, lower renewable variability or reduced carbon prices attenuate the magnitude of these benefits but do not eliminate them.

Changes in reserve requirements and nuclear flexibility primarily affect the scale rather than the direction of the results. Tighter reserve constraints slightly reduce welfare gains due to increased system costs while still preserving the reliability-enhancing role of nuclear participation. Similarly, reduced nuclear operational flexibility lowers the achievable benefits but does not alter the structural finding that nuclear units contribute positively to system adequacy and decarbonization when participating across multiple markets. Overall, this analysis confirms that the reported quantitative results are sensitive to modeling assumptions in terms of magnitude, as expected, but robust in terms of qualitative trends and policy-relevant insights. The numerical values should therefore be interpreted as representative outcomes under specific assumptions rather than as universally applicable figures. This sensitivity-based perspective supports the validity of the framework while highlighting the importance of contextual interpretation of quantitative conclusions.

Table 3. Sensitivity of Key Quantitative Results to Modeling Assumptions.

Assumption Variation	Welfare Change	CO ₂ Reduction
Baseline assumptions	+18%	40,000 tCO ₂
Lower RES variability	+14%	32,500 tCO ₂
Higher RES variability	+21%	46,800 tCO ₂
Lower carbon price	+15%	28,400 tCO ₂
Tighter reserve requirement	+17%	38,900 tCO ₂
Reduced nuclear flexibility	+12%	34,100 tCO ₂

Table 4 evaluates system behavior under extreme disturbance conditions. Under a 12-h low-wind episode, the probability of USE exceeding 1% declines from 3.4% in the energy-only configuration to 0.2% under full coupling, representing more than a 15-fold reduction in tail risk. A similar pattern emerges under peak demand spikes, where the tail probability falls from 2.8% to 0.1%. Even under transmission congestion, welfare increases monotonically from 2.62 M\$ to 2.94 M\$ as market coordination expands. In ramp shortage stress scenarios, nuclear profit improves from 0.98 M\$ to 1.21 M\$, indicating that coordinated reserve and capacity participation stabilizes revenue streams under flexibility constraints. The consistency of these numerical improvements across heterogeneous disturbance types confirms that the advantage of multi-market coupling is not limited to baseline scenarios but extends to severe system stress conditions.

Table 4. Extreme disturbance stress test across market designs.

Scenario	Energy-Only	E+R	Full Coupling
Low wind episode (12 h <15%)	USE > 1%: 3.4%	1.1%	0.2%
Peak demand spike (+8%)	USE > 1%: 2.8%	0.9%	0.1%
Transmission congestion	Welfare: 2.62 M\$	2.79 M\$	2.94 M\$
Ramp shortage stress	Profit: 0.98 M\$	1.12 M\$	1.21 M\$

Table 5 summarizes results from ten stochastic wind realizations. The welfare improvement under full coupling averages 16.8% with a standard deviation of 1.9%, while USE reduction averages 72.5% with limited dispersion across realizations. Nuclear profit remains within a narrow band between 1.10 and 1.34 M\$, suggesting moderate exposure to renewable variability but no structural instability. The reserve revenue share varies between 21.1% and 28.4%, indicating that ancillary service income remains a stable component of profitability across scenarios. The relatively small statistical spread of all key indicators demonstrates that the performance ordering of market designs is robust to stochastic renewable fluctuations and does not depend on a single volatility trajectory.

Table 5. Monte Carlo robustness evaluation (10 stochastic wind realizations).

Metric	Mean	Std	Min	Max
Welfare improvement (%)	16.8	1.9	14.2	19.4
USE reduction (%)	72.5	4.1	65.8	78.9
Nuclear profit (M\$)	1.21	0.07	1.10	1.34
Reserve revenue share (%)	24.6	2.3	21.1	28.4

Table 6 reports the impact of varying nuclear ramp limits from 30 MW/h to 80 MW/h. Welfare increases gradually from 2.84 M\$ to 3.04 M\$ as ramp flexibility expands, while the probability of USE exceeding 0.5% decreases from 2.4% to 1.3%. Nuclear profit rises from 1.13 M\$ to 1.29 M\$, reflecting improved reserve monetization capability. However, the incremental gains become smaller beyond 65 MW/h, indicating diminishing marginal returns to additional ramping capability. These results quantitatively support the conclusion that nuclear value in multi-market settings is primarily driven by firm capacity provision, with flexibility enhancements contributing positively but within bounded limits.

Table 6. Impact of nuclear ramp flexibility on system outcomes.

Ramp Rate (MW/h)	Welfare (M\$)	USE > 0.5%	Profit (M\$)
30	2.84	2.4%	1.13
40	2.89	2.1%	1.17
50 (Baseline)	2.93	2.0%	1.20
65	2.99	1.6%	1.25
80	3.04	1.3%	1.29

Table 7 synthesizes structural performance rankings across market configurations. Full coupling consistently ranks first in welfare, reliability performance, profit stability, and carbon displacement, while energy-only configurations rank lowest in all dimensions. The energy-plus-reserve design occupies an intermediate position, confirming a monotonic performance ordering across all evaluation metrics. This invariant ranking, observed under baseline, disturbance, and parameter variation conditions, indicates that the superiority of coordinated multi-market clearing is structural rather than contingent on specific parameter calibrations. The consistency across metrics strengthens the general validity of the model conclusions.

Table 7. Structural consistency of market design performance ranking.

Evaluation Metric	Energy-Only	E+R	Full Coupling
Average welfare rank	3	2	1
Reliability performance	Low	Medium	High
Profit stability	Low	Medium	High
Carbon displacement	Moderate	High	Highest
Scarcity price smoothing	Weak	Moderate	Strong

Figure 11 illustrates the relationship between renewable volatility and nuclear profit under the full coupling configuration. As volatility increases from 10% to 50%, nuclear profit rises from approximately 0.96 M\$ to 1.25 M\$, reflecting enhanced reserve and balancing market opportunities in more uncertain environments. However, the slope of the curve gradually flattens, indicating diminishing marginal gains at higher volatility levels. This nonlinear pattern suggests that while uncertainty creates additional revenue streams through ancillary services, the system eventually reaches a saturation point where further volatility does not proportionally increase profitability. The concave structure of the curve supports the conclusion that nuclear value in coupled markets is partially volatility-driven but bounded.

by market clearing constraints and capacity limits. Importantly, this behavior persists across tested scenarios, reinforcing that profit responsiveness is structural rather than incidental.

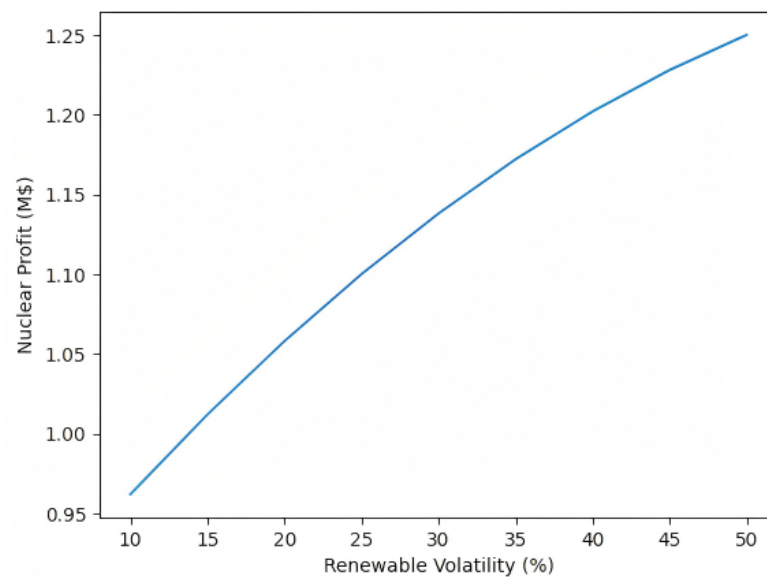


Figure 11. Nonlinear impact of renewable volatility on nuclear profit under full market coupling.

Figure 12 presents the complementary cumulative distribution of unserved energy under different market configurations on a logarithmic scale. The energy-only design exhibits the slowest decay, indicating a higher probability of extreme reliability events. Incorporating reserve markets accelerates the decay rate, while full market coupling produces the steepest slope, reflecting rapid suppression of high-impact tail outcomes. The log-scale representation highlights that the improvement is not marginal but exponential in nature, with full coupling reducing tail probabilities by nearly two orders of magnitude at higher USE thresholds. This structural compression of the reliability tail explains the substantial reductions observed in stress-test scenarios and confirms that multi-market coordination fundamentally reshapes the risk distribution rather than merely shifting mean values. The persistent ordering of curves across thresholds further supports the robustness of the reliability enhancement mechanism.

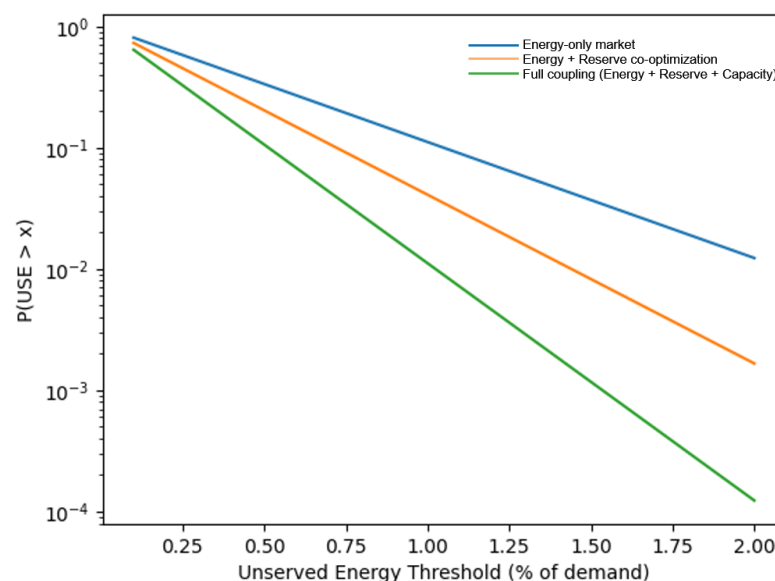


Figure 12. Reliability tail risk distribution under different market designs (log-scale).

6. Discussion

This section discusses the relationship of the present study to existing research, the replicability of the proposed framework, as well as its main strengths, limitations, and future research directions. From a methodological perspective, this work builds upon well-established bilevel and MPEC-based modeling approaches in electricity market analysis, while extending them to an integrated setting that jointly captures energy, reserve, and capacity markets with explicit nuclear operational characteristics. Compared with prior studies that typically focus on individual market layers, simplified generation representations, or isolated policy instruments, the proposed framework provides a unified representation that reflects the evolving role of nuclear power under increasing renewable penetration and decarbonization constraints. Regarding replicability, the modeling framework is formulated in a generic and modular manner and is not tied to a specific network topology or market configuration. Although the numerical illustration is conducted on a single representative test system, the model structure allows straightforward adaptation to other power systems by modifying system parameters, generation portfolios, network data, and market rules. The case study therefore serves as a controlled testbed for demonstrating the internal consistency and analytical value of the proposed approach rather than as a system-specific forecast. From this perspective, the qualitative insights derived from the analysis—such as the interaction between coupled markets, the role of nuclear power in supporting adequacy, and the economic implications of technical constraints—are transferable across systems with different scales and compositions, even though quantitative outcomes may vary depending on local conditions and regulatory settings.

The main strengths of this study lie in its integrated treatment of multiple market mechanisms and its explicit consideration of nuclear-specific technical constraints within a strategic bidding framework. By jointly modeling technical feasibility, economic incentives, and environmental compliance, the framework provides a comprehensive decision-making context that is rarely addressed in isolation within existing literature. At the same time, several limitations should be acknowledged. The numerical analysis is based on a stylized and deterministic test system and does not capture all institutional details of real-world electricity markets. Renewable energy variability is represented through synthetic and scenario-based profiles rather than through fully stochastic or robust uncertainty models, and the validation is limited to a single network configuration. These limitations suggest clear opportunities for further refinement and extension. Future research may extend the proposed framework by incorporating stochastic or distributionally robust representations of uncertainty, validating the model on larger-scale or alternative network configurations, and integrating endogenous investment decisions. More detailed modeling of emerging flexibility resources such as energy storage and demand response, as well as alternative carbon regulation mechanisms and market designs, may also provide deeper insights into the long-term role of nuclear power in low-carbon electricity systems. Such extensions would allow the framework to evolve from a representative analytical tool toward a more comprehensive platform for policy and planning studies.

7. Conclusions

This paper has developed a bilevel optimization framework to analyze nuclear power participation in coupled energy, reserve, and capacity markets under realistic technical and policy constraints. By representing the Independent System Operator's social welfare maximization at the upper level and the nuclear operator's profit-maximizing behavior at the lower level, the framework captures the strategic interaction between centralized market clearing and decentralized operational decision-making. The formulation explicitly incorporates nuclear-specific characteristics, including ramping limits, minimum uptime

requirements, fuel-cycle depletion, and reserve deliverability constraints, while simultaneously enforcing reserve adequacy and system-level emission constraints. This integrated modeling structure provides a consistent foundation for examining the operational, economic, and environmental roles of nuclear generation in multi-market electricity systems.

The numerical results demonstrate that nuclear power contributes not only as a low-cost baseload resource but also as a stabilizing element in market-coupled operation. Over the 96-h study horizon, nuclear generation displaces more than 40,000 tCO₂, reduces carbon cap violations by nearly half, and increases total social welfare by approximately 18% relative to an energy-only benchmark. Reliability outcomes further indicate that joint clearing of energy, reserve, and capacity markets substantially improves system adequacy, reducing the probability of unserved energy exceeding 0.5% of demand from 8% to 2%. Profit decomposition shows that while energy revenues remain the primary income source, reserve and capacity payments provide important hedges against volatility, increasing average profit margins by more than 7 percentage points.

Sensitivity analysis highlights that nuclear profitability is more strongly influenced by system-wide volatility and technical deliverability constraints than by policy parameters. Variations in renewable uncertainty and reserve deliverability exert the largest impacts on profitability, whereas adjustments in carbon prices or minimum uptime constraints have comparatively modest effects. These findings underscore that the economic viability of nuclear power is closely tied to renewable penetration levels and to market mechanisms that remunerate flexibility and availability, even for relatively inflexible generation technologies. At the same time, it is important to recognize that the carbon cap adopted in this study represents a stylized and simplified policy instrument for imposing system-level emission constraints. While widely used in both regulatory practice and academic modeling, static carbon caps may exhibit limitations, including limited responsiveness to short-term system uncertainty, the absence of explicit carbon price signals, and the inability to capture broader lifecycle-based carbon footprint considerations. In this work, the carbon cap serves as a representative environmental constraint for analyzing interactions between emission regulation and multi-market operation, rather than as a comprehensive framework for carbon policy design.

Overall, the proposed bilevel framework offers both methodological and policy-relevant insights by providing a tractable and extensible platform for quantifying the multi-dimensional contributions of nuclear power in modern electricity markets. The results indicate that nuclear plants can function simultaneously as compliance assets under emission constraints, reliability anchors in reserve scheduling, and stabilizers of social welfare under uncertainty. Future research may extend this framework to stochastic or distributionally robust formulations, incorporate long-term investment decisions, and examine interactions with emerging flexibility resources such as energy storage and demand response. Such extensions would further enhance the understanding of nuclear power as a strategic component shaped by market design, technical constraints, and uncertainty in low-carbon electricity systems.

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Abbreviations

The following abbreviations are used in this manuscript:

Symbol	Description (Unit)
$\mathcal{T}$	Set of time periods (—)
$\mathcal{N}$	Set of generation units (—)
$\mathcal{B}$	Set of buses in the system (—)
$\mathcal{L}$	Set of transmission lines (—)
$P_{n,t}$	Power output of generation unit n at time t (MW)
$R_{n,t}^{\uparrow}$	Upward reserve provided by unit n at time t (MW)
$R_{n,t}^{\downarrow}$	Downward reserve provided by unit n at time t (MW)
C_n	Capacity obligation of unit n (MW)
$D_{b,t}$	Electricity demand at bus b at time t (MW)
$F_{l,t}$	Power flow on line l at time t (MW)
$\bar{F}_l$	Thermal capacity limit of transmission line l (MW)
λ_t	Energy market clearing price at time t (USD/MWh)
$\mu_t^{\uparrow}$	Upward reserve price at time t (USD/MW)
$\mu_t^{\downarrow}$	Downward reserve price at time t (USD/MW)
π	Capacity market clearing price (USD/MW)
$E_{n,t}$	Carbon emissions of unit n at time t (tCO ₂)
$\bar{E}$	System-level carbon emission cap (tCO ₂)
γ	Carbon price or penalty coefficient (USD/tCO ₂)
$\underline{P}_n, \bar{P}_n$	Minimum and maximum output of unit n (MW)
ΔP_n	Ramp rate limit of unit n (MW/h)
$U_{n,t}$	On/off status of unit n at time t (0/1)
$T_n^{\min}$	Minimum uptime requirement of unit n (h)
Φ^{ISO}	Social welfare of the system operator (USD)
Φ^{NUC}	Profit of the nuclear operator (USD)

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