Under the Hood: Penalty Parameters for System Constraint Violations in Short-Term Wholesale Electricity Market-Clearing Mechanisms

Luca Cantoni[*] Valerio Catalano[†] Christoph Graf[‡] Federico Quaglia[§]
Andrea Terracciano[¶] Frank A. Wolak[||]

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Abstract

This paper compares short-term wholesale market designs and operating practices in Europe and the United States. We review various implementations of soft constraints, which allow limited violations of system operating constraints subject to administrative penalty costs. Although relaxing system constraints can help obtain feasible solutions within the allotted computational time, it may also increase the operational risks associated with maintaining secure system operation. We discuss approaches for determining penalty parameters and prioritization schemes across multiple system constraints based on cost-benefit considerations.

Keywords: Real-time markets and operations, soft constraints, constraint violation penalties

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[*] Terna S.p.A., Viale Egidio Galbani, 70, 00156 Rome, Italy, luca.cantoni@terna.it.

[†] Terna S.p.A., Viale Egidio Galbani, 70, 00156 Rome, Italy, valerio.catalano@terna.it.

[‡] Institute for Policy Integrity, New York University, New York, NY 10012, United States and Program on Energy and Sustainable Development (PESD), Stanford University, Stanford, CA 94305-6072, United States, christoph.graf@nyu.edu.

[§] Terna S.p.A., Viale Egidio Galbani, 70, 00156 Rome, Italy, federico.quaglia@terna.it.

[¶] Terna S.p.A., Viale Egidio Galbani, 70, 00156 Rome, Italy, andrea.terracciano@terna.it.

[||] Department of Economics and Program on Energy and Sustainable Development (PESD), Stanford University, Stanford, CA 94305-6072, wolak@zia.stanford.edu.

1 Introduction

In short-term wholesale electricity markets, clearing algorithms match thousands of willingness to supply energy offers with willingness to consume energy bids to determine unit-level schedules for generation, consumption, and storage resources. These market-clearing algorithms are typically formulated as constrained optimization problems, e.g., maximizing joint producer and consumer surplus based on market offers and bids, or minimizing total as-offered costs to serve inelastic locational energy demands bids, subject to unit operating constraints and transmission network constraints.

The complexity of these market-clearing algorithms depends on extent to which transmission and generation unit operating constraints are accounted for in the short-term market design. In practice, two principal models can be identified [Hogan, 2021, Graf, 2025]: (i) integrated locational marginal pricing (nodal) markets that support secure real-time system operation and account for the complexity of the electric system transparently from the day-ahead forward financial market to the real-time market operation; and (ii) sequential markets, which rely on an initial simplified market-clearing ignoring many relevant system constraints, to be resolved later (if binding) reactively, so as not to compromise real-time system security.

Central to the integrated market design is the offer- and bid-based security-constrained unit commitment and economic dispatch (SCUC-ED) problem. This formulation incorporates operational constraints at both the unit level and the system level and co-optimizes energy, congestion management, and ancillary services. Transmission constraints bound the power flows that are governed by Kirchhoff's laws, yet the underlying equipment can typically tolerate small deviations from its rated operating limits. Therefore, regions operating under this market design do *not* model these constraints as hard constraints, but allow for small constraint violations which are penalized, an approach known as soft-constraint approach.

This soft-constraint approach allows for deviations from the limit using slack variables that are penalized in the objective function. The parametrization of the penalty function is typically subject to stakeholder discussion and debate in all U.S. short-term markets. The usage of soft-constraints has two advantages: (i) it makes it typically easier to find feasible solutions to the SCUC-ED within the allotted time; and (ii) locational marginal prices (LMPs) signal scarcity if a constraint is violated rather than committing a generation unit or set of units that depresses locational marginal prices at certain grid locations and increase the overall cost of meeting the locational demands for energy and operating reserves because of higher as-offered start-up costs and minimum load costs associated with committing these units.

When system constraints are enforced strictly, i.e., under a hard-constraint approach, the solution must satisfy all requirements regardless of the associated cost. For example, even a small shortfall of a few megawatts over a brief interval in meeting the minimum balancing capacity requirement may trigger the start-up of an additional generating unit. This action incurs start-up costs and requires the unit to remain online for several hours due to minimum up-time constraints. Consequently, a negligible risk associated with a minor constraint violation can result in substantial costs, as well as increased emissions from potentially less efficient units. In contrast, a soft-constraint approach can avoid such unnecessary and costly start-ups.

Most sequential markets, do use less advanced optimization tools for their initial financial market clearings (day-ahead, intraday) but still need to operate the system securely in real-time even if these initial market solutions turns out to be physically infeasible when matched to the actual system operating constraints, rather than the assumed simplified transmission network generation unit operating constraints. In that case, system operators employ a variety of tools to manage binding system constraints during real-time operations. Most European system operators, as surveyed in this paper, use less integrated tools to manage real-time operations.

This paper first reviews how system operators allow for constraint violations of system constraints in their market-clearing models and operational procedures. We first discuss, the reliability risk–operating cost trade-off between a hard- and a soft-constraint approach to clear the short-term markets. Under the soft-constraint approach (some) system constraints, e.g., the thermal line limit of a transmission line, or a reserve requirement, can be slightly violated with a dollar per MW penalty on the slack variable associated with the soft constraint in the objective function. Because this flexibility increases the feasible set of the optimization problem, it is typically easier to find a feasible solution more quickly.[1] However, if system constraints are relaxed within the soft-constraint paradigm, the resulting solution can lead to an increased reliability risk in real-time

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[1] As discussed in Section 3, truly optimal solutions are often unattainable due to the complexity of the problems and the time limit to find a market solution.

system operation. Conversely, relying on a hard-constrained approach may result in no feasible solution, necessitating manual fallback procedures to operate the system. These procedures introduce their own operational reliability risks and can lead to suboptimal outcomes.

Second, we emphasize the need for cost-benefit justified penalty (functions) of system constraints. It is ex-ante not clear how to set their absolute levels and relative priorities. In the organized U.S. wholesale markets,[2] a stakeholder process guides the choice of these constraint violation penalty functions.

Third, we provide an extensive review of current practices in markets in the U.S. and Europe. While all organized U.S. markets have transitioned to an integrated market with locational marginal pricing that supports the secure operation of the system in real-time, many European countries use a sequential process. Initially, a zonal market ignoring many relevant system constraints is operated and later the resulting or nominated schedules are converted into feasible schedules through a redispatching process[3] [Graf, 2025]. Many European system operators currently redispatch “manually,” which means they often are implicitly using a soft-constrained approach but less defined as it is in the organized markets in the U.S.

The remainder of this paper is organized as follows. Section 2 reviews short-term market design frameworks and real-time operational procedures in Europe and the U.S. Section 3 discusses the soft-constraint approach for system constraints, including penalty parameter selection and constraint prioritization. Sections 4 and 5 survey current soft-constraint practices in Europe and the U.S., respectively. Section 6 concludes.

2 Short-Term Market Design Frameworks and Real-Time Operations

This section reviews the two prevailing short-term electricity market designs: integrated markets and sequential zonal markets. Both short-term market designs support hedging against real-time market outcomes[4] through financial day-ahead (and intraday) markets, however, the structure and implementation of these markets differ.

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[2] These are markets administered by an Independent System Operator (ISO) or Regional Transmission Operator (RTO). The distinction between the two is minor and not relevant for the scope of this paper. See Federal Energy Regulatory Commission [2025] for more details.

[3] Other terms such as balancing mechanisms, technical constraints market, congestion management are also used for the same purpose.

[4] Financial hedging can mitigate market power in the real-time market [see, e.g., Wolak, 2000, 2007].

The integrated market design explicitly incorporates all relevant operating constraints on generation and storage resources, and the transmission grid into the financial day-ahead market-clearing process. As a result, the schedules for generation, storage, and demand emerging from the day-ahead market are physically feasible. These engineering constraints are consistently represented across all market stages, from day-ahead through real-time. By jointly accounting for economic objectives and the engineering constraints of both market resources and the transmission grid, this design supports the secure real-time system operation of the grid.

In contrast, the sequential zonal market design begins by clearing a simplified financial market, across the day-ahead and intraday stages, that ignores many of the constraints necessary for secure real-time operation. These unconstrained market schedules are subsequently adjusted through reactive measures such as redispatch to produce schedules that are operationally feasible. This disintegrated market design can lead to higher overall costs[5] and may not be as reliable.[6]

Early organized short-term markets in the United States—California ISO, PJM Interconnection, ISO New England, and Electricity Reliability Council of Texas (ERCOT)—employed sequential zonal markets. These regions subsequently adopted integrated market designs. The remaining three organized markets in the United States, New York ISO, Midcontinent ISO (MISO), and Southwest Power Pool (SPP), were established as integrated markets from the beginning. Sequential zonal market designs remain the prevailing approach in Europe.

2.1 Integrated Market

The integrated market-clearing uses a single algorithm to jointly procure energy and ancillary services, ensuring full co-optimization between products. This process incorporates physical unit-level operating constraints and system-related constraints, including transmission limits. The resulting locational marginal prices (LMPs) support the secure real-time operation of the system.[7]

These granular price signals also promote allocative efficiency: LMPs represent the increase in

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[5] See, e.g., Hogan [1998], Alaywan et al. [2004], Wolak [2011], Triolo and Wolak [2022] on market efficiency improvements after transitioning from a simplified market to an integrated market. Brown and Reguant [2026] find substantial net consumer benefits of renewable expansion on final total electricity prices in Spain, but call for market reforms to cost-effectively manage increasing levels of renewable generation in real-time.

[6] Daví-Arderius and Graf [2025] demonstrate an increase in redispatch volumes and costs in response to the Iberian Blackout in 2025.

[7] Automated market power mitigation is another feature in many integrated short-term electricity markets across the U.S. [see, e.g., Graf et al., 2021].

the as-offered cost of serving an additional MWh of demand at a given node, taking into account all relevant operating constraints on the transmission network and generation units [Wolak, 2021].

The market is first cleared for all 24 hours of the following day using offered-in supply and bid-in demand. In real-time this process is repeated with realized locational demands. Because the market-clearing mechanism accounts for the technical constraints of generation and storage units, the generation, storage, and demand schedules resulting from each stage are physically feasible, given all operating constraints on generation units and the transmission network.

To address pricing issues arising from non-convex unit commitment constraints, these markets typically include make-whole payments. These payments compensate generators whenever daily revenues from selling energy and operating reserves are insufficient to cover their accepted as-offered costs of providing these products, thereby ensuring cost recovery and preserving incentive compatibility, in the sense that at the end of the operating day no supplier regrets incurring the cost of starting up its units to supply the energy and operating reserves sold during that day [see, e.g., Graf et al., 2020a, Graf, 2025].

Even though the system constraints explicitly accounted for in the short-term market-clearing mechanisms of all organized wholesale markets throughout the U.S. are firm, small temporal deviations typically do not jeopardize system security. Therefore, all U.S. markets use a soft-constraints approach to allow for small, penalized deviations from operational limits. Section 5 surveys the different approaches and details across the various organized short-term market implementations across the U.S.

2.2 Sequential Zonal Market

Under the sequential zonal market design, energy and ancillary services are procured separately, meaning there is no co-optimization between products. Ancillary services are typically procured through three primary mechanisms: (i) reserve auctions held prior to clearing energy markets; (ii) real-time energy balancing markets that activate offers in merit order; and (iii) redispatching schemes designed to resolve residual constraints, such as congestion and voltage regulation. Because resolving congestion can also at the same time free up reserves or reduce system imbalances, dividing these inherently interconnected services into separate products may increase the cost of reliable system operation.

In sequential zonal markets, energy and operating reserve markets generally account for only a limited set of transmission constraints, adopting, at best, a simplified representation of the network. In many instances, the power system is divided into several large geographic (bidding) zones, and only the transmission capacity limits between these zones are considered during market clearing. Within these bidding zones, the zonal market model effectively assumes infinite transmission capacity. This is the default model in Europe, where bidding zone boundaries often coincide with national borders [European Commission, 2015, Graf, 2025, Papavasiliou and Ávila, 2026].

Due to these simplifications, clearing the zonal market is computationally less demanding, and price formation may appear more "intuitive." However, zonal markets may result in inefficient dispatch and inaccurate locational generation, storage, and transmission network investment signals when intra-zonal congestion is significant or more generally if system constraints other than the aggregate energy balance are dominant. This occurs because network constraints are only partially reflected in prices, requiring residual issues to be managed through redispatch or other corrective actions [Graf et al., 2020b].

All zonal markets are eventually centrally managed because system operators resolve system constraints if initial market schedules are incompatible with secure grid operation. In many cases, the procedures for redispatch are manual, where real-time power flow simulations are performed using actual or predicted close-to-real-time market schedules to identify security constraint violations. The interconnected nature of the system makes this approach inefficient: relieving one constraint can trigger constraint violations elsewhere, as power flows distribute according to Kirchhoff's laws.

All zonal markets are eventually centrally managed because system operators must change the operating levels of generation, storage, or loads if initial market schedules are incompatible with secure grid operation. In many cases, the procedures for redispatch are manual, where real-time power flow simulations are performed using actual or predicted close-to-real-time market schedules to identify security constraint violations. The interconnected nature of the system makes this approach unnecessarily costlybecause addressing one constraint can trigger additional violations in other parts of the system because of Kirchhoff's laws.

The inherent imprecision in operator judgment applied during these reactive procedures can be interpreted as a soft-constraint approach to addressing system constraints. Section 4 surveys these different approaches and provides details regarding the operational management practices of various European system operators.

3 Soft-Constraints and Penalty Parameter Selection

Conventional generation units have non-convex production costs, i.e., start-up costs [Reguant, 2014, Graf et al., 2020a, Jha and Leslie, 2025], therefore most advanced market-clearing algorithms solve a mixed-integer convex program (MICP) to capture the binary decisions of starting-up or shutting-down a unit.

Consider a MICP with linear objective and constraint functions, which reduces to a mixed-integer linear program (MILP) that captures the non-convex production costs. Formally,

$$\min\{c^\top x : Ax \leq b,\ x \in \mathbb{Z}^p \times \mathbb{R}^q\}, \tag{1}$$

with $A \in \mathbb{R}^{m\times(p+q)}$, $b \in \mathbb{R}^m$, and $c \in \mathbb{R}^{p+q}$, whereas the objective is to find the vector x, with p integer and q continuous components, that minimizes the linear cost $c^\top x$ while satisfying all constraints $Ax \leq b$. A soft-constraint formulation or penalty relaxation of the MILP above is then defined as

$$\min\{c^\top x + \lambda^\top s : Ax \leq b + s,\ s \geq 0,\ x \in \mathbb{Z}^p \times \mathbb{R}^q,\ s \in \mathbb{R}^m\}, \tag{2}$$

whereas the vector of slack variables s absorbs constraint violations ($Ax \leq b + s$). $\lambda \in \mathbb{R}^m_{++} = \{x \in \mathbb{R}^m : x > 0\}$ controls the penalty per MW for each violated constraint. Larger values of the elements of λ force the solver to have a smaller quantity of constraint violations. As $\lambda \to \infty$ the soft-constraint problem in (2) becomes the hard-constrained problem in (1).

Any feasible solution of (1) is also feasible for (2). However, if (1) was infeasible, the relaxed problem may not be. Formally, the feasible set $X \subseteq X_s$, where X is defined by the hard constraints of (1) and X_s by the relaxed constraints of (2), since any x satisfying $Ax \leq b$ also satisfies $Ax \leq b+s$ for $s \geq 0$. Figure 1 illustrates the relaxation of a nonempty feasible set. Note that such relaxation can also render an infeasible (empty) set feasible.

However, it should be noted that (2) is a different problem from (1). By definition the solution to (2) may not be a solution to (1). Furthermore, because (2) is a less tight formulation of the original problem, convergence to the optimal solution may take longer [Klotz and Newman, 2013].[8]

Designing system constraint violations penalty parameters means defining the maximum level of a constraint violation and the corresponding monetary penalty values. Because power systems face multiple system constraints, e.g., transmission, reserve requirements, etc., the penalty values create a hierarchy or prioritization among them if set to different values. Furthermore, constraint violations of one or several constraints at the same time may increase the risk of securely operate the system in real-time [Daví-Arderius and Graf, 2025].

In the U.S., finding the parametrization of these penalties or penalty functions that balances the reliability risk–operating cost trade-off is typically subject to stakeholder discussion. The parameters should be updated periodically as the power system evolves. For example, increased flexibility provided to the market through battery energy storage systems, demand-side flexibility, advanced transmission technologies, and grid-enhancing technologies [see, e.g., Zhou et al., 2025], may reduce the need for a soft-constraint approach for many operating constraints.

The introduced flexibility of soft-constraints may increase locational marginal energy prices or reserve prices as they also signal the scarcity value if a constrained is violated. This increase can be offset though, by committing less units which means lower as-offered start-up costs and minimum load costs.

4 Current Practices Among System Operators in Europe

The structure of the European internal electricity market is centered on the Single Day-Ahead Coupling (SDAC), a pan-European mechanism designed to allocate cross-border transmission capacities and facilitate financial trading across Europe [ENTSO-E, 2025b, Madani and Starnberger, 2025]. The EUPHEMIA (Evolutionary Pan-European Market Coupling, Hybrid Expert-based Integrated Algorithm) algorithm is used to clear the day-ahead market. EUPHEMIA is formulated as

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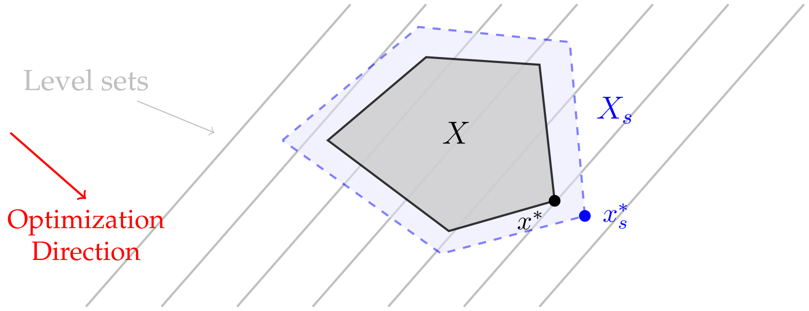
[8] Commercial solvers typically use Branch and Bound (B&B) in combination with cutting planes to solve large-scale real-world MICPs [Gurobi Optimization, LLC, 2026].

Figure 1: Relaxation of a Nonempty Feasible Set



Notes: Original feasible set $X = \{X \in \mathbb{R} : Ax \leq b\}$ and relaxed feasible set $X_s = \{x \in \mathbb{R} : Ax \leq b + s\}$ with $s \geq 0$. The optimal solutions for the original and relaxed systems are x^* and x_s^*, respectively.

a MILP with the objective of maximizing the total consumer and producer surplus across coupled regions, based on market offers and bids. EUPHEMIA integrates network constraints between bidding zones adopting two approaches: (i) net transfer capacity (NTC); and (ii) flow-based market coupling [Nagy et al., 2025, Schavemaker, 2025].[9]

Bidding zones are static and typically coincide with the borders of EU member states, as shown in Figure 2. EUPHEMIA can account for complex bidding products, e.g., block bids, linked orders, and flexible profiles, but its scope is strictly limited to an "energy-only" market paradigm using a simplified network topology [see, e.g., Hübner and Hug, 2026]. The clearing process focuses exclusively on the commercial exchange of energy and the management of congestion between large bidding zones, without accounting for the dynamic stability of the power system and local technical constraints. Constraints in EUPHEMIA are treated as hard constraints. Solvability is ensured through a sequence of algorithmic steps that iteratively remove combinations of complex orders, particularly block orders, that cause infeasibility. When the initial optimization problem cannot be solved, the algorithm prunes conflicting orders and re-optimizes until a feasible solution is obtained while preserving the integrity of network constraints and uniform pricing within bidding zones [All NEMO Committee, 2025].

The day-ahead market is complemented by continuous trading and auction based intraday market sessions that allows market participants to update their financial day-ahead market po-

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[9] The NTC model is typically employed in regions with simpler grid topologies or where the flow-based methodology has not yet been implemented, as it represents cross-zonal capacity through rigid bilateral limits on individual interconnections. The flow-based model is instead preferred in highly meshed and interdependent transmission networks, such as the Central Western Europe (CWE) region, where it allows for a more accurate representation of physical power flows and a more efficient utilization of the existing infrastructure.

sitions and trade up to close-to-real-time [see, e.g., Ocker and Jaenisch, 2020, Graf et al., 2024]. Similar to the SDAC the Single Intraday Coupling (SIDC) aims to create a single EU cross-zonal intraday market. In the continuous trading intraday market, buy and sell orders are matched according to a first-come-first-served principle, with priority given to the highest buy price and the lowest sell price. A distinctive feature of the SIDC is the implicit allocation of cross-zonal transmission capacity: rather than being priced and auctioned separately, transmission capacity is allocated simultaneously with energy in the moment two orders are matched. An order submitted for a delivery area different from the participant's own can be executed only if sufficient transmission capacity is available on the relevant interconnections. Upon matching, the Shared Order Book (SOB) and the Capacity Management Module (CMM) are updated instantaneously, with matched orders removed from the former and available transmission capacity on the affected borders reduced accordingly in the latter. Trade data, encompassing both cross-zonal transactions and trades concluded between different Nominated Electricity Market Operators (NEMOs) within the same delivery area, are collected by the Shipping Module (SM), enriched with information provided by Transmission System Operators (TSOs), Central Counterparties (CCPs), and shipping agents, and subsequently disseminated to all relevant parties at pre-configured intervals [ENTSO-E, 2025c, Blana, 2025, Schrade, 2025, Tolstrup, 2025, Vogeler, 2025].

Because the European day-ahead and intraday markets do not necessarily lead to schedules that are operationally feasible, the responsibility for maintaining system security and operational adequacy shifts to the national Transmission System Operators (TSOs) following the day-ahead market clearing. The procurement of ancillary services, such as frequency regulation, voltage control, and the resolution of local network congestion, is managed through dedicated national markets or balancing mechanisms. These processes are governed by heterogeneous domestic regulations and distinct algorithmic approaches, ranging from co-optimization approaches conditional on day-ahead market schedules to iterative technical adjustments by the TSO. This decoupling highlights a significant transition from a unified European energy trading to a fragmented, TSO-specific, management of grid reliability.

TSOs in major European countries typically procure ancillary services through dedicated market sessions, usually segmented by type of service [CRE, 2025, RTE, 2025]. In particular, balancing capacity is usually procured via dedicated auctions (one for each product), typically held before

Figure 2: Static Bidding Zones Used to Clear the European Day-Ahead and Intraday Markets

Notes: Boundaries may have changed since the original publication. Source: ACER [2022].

the day-ahead energy market clearing. This design is consistent with the European framework established under the Commission Regulation (EU) 2017/2195, which defines standard balancing products and requires TSOs to procure balancing capacity through transparent market-based mechanisms [European Commission, 2017, ENTSO-E, 2025a]. For example, most Continental European TSOs procure Frequency Containment Reserves (FCR) through the *FCR Cooperation*, a regional initiative pooling offers from Germany, Austria, Belgium, the Netherlands, Switzerland, France, Denmark, Slovenia, and the Czech Republic into a Common Merit Order List (CMOL). Auctions are held daily on D-1 for six four-hour blocks, offers must be symmetric in the upward and downward direction, and clearing follows a uniform marginal pricing rule; capacity remuneration only covers availability in MW, with no separate payment for activated energy [ENTSO-E, 2026]. Another example is provided by the auctions for automatic Frequency Restoration Reserves (aFRR) that the four German TSOs use to procure reserve capacity. Daily pay-as-bid auctions are held on a common platform, with gate closure at 9:00 a.m. (CET) on the day prior to the operating day for four-hour products. Unlike FCR, aFRR bids may be asymmetric, with separate offers for upward and downward capacity, reflecting the directional nature of secondary frequency regulation [regelleistung.net, 2025].

Balancing energy is activated both through pan-European platforms, such as TERRE[10] platform (RR), MARI[11] platform (mFRR), PICASSO[12] platform (aFRR), and through national real-time balancing markets operated by individual TSOs. The European platforms enable the cross-border exchange of balancing energy and represent cross-zonal transmission constraints only. They are complemented with national real-time balancing markets.

Congestion management and voltage constraints are typically addressed through separate operational redispatch or remedial actions, and are only rarely integrated directly into the real-time balancing optimization [RTE, 2024]. This layered operational structure is widely described in European system operation frameworks such as the Commission Regulation (EU) 2017/1485 [European Commission, 2017].

This segmented and sequential approach significantly simplifies the algorithmic complexity required at each stage, thereby reducing computational time and lowering the risk of infeasibility in market-clearing and balancing algorithms. As a result, the need to introduce soft constraints or rely on successive constraint relaxation mechanisms is considerably reduced.

It should be noted, however, that this sequential and often non-integrated structure comes with inherent trade-offs. Because energy markets, ancillary service procurement, and congestion management are handled in separate stages, each conditioned on the outcomes of the preceding one, system constraints that are binding across multiple dimensions may not be addressed jointly. In particular, interactions between congestion, reserve adequacy, and voltage regulation are not captured within a single co-optimization framework, which can limit the ability to identify least as-offered cost solutions at the system level.

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[10] TERRE (Trans European Replacement Reserves Exchange) is a pan-European platform for the exchange of Replacement Reserves (RR) balancing energy across European countries.

[11] MARI (Manually Activated Reserves Initiative) is a pan-European platform for the exchange of manual Frequency Restoration Reserves (mFRR) balancing energy.

[12] PICASSO (Platform for the International Coordination of Automated Frequency Restoration and Stable System Operation is a pan-European platform for the exchange of automatic Frequency Restoration Reserves (aFRR) balancing energy.

5 Current Practices Among System Operators in the U.S.

The U.S. electric grid is managed by several Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs), each responsible for a specific area of the country (see Figure 3). Operationally, these entities are the U.S. counterparts to the European Transmission System Operators (TSOs) and their primary mandate is to ensure the safety and reliability of the power system, while also operating energy and ancillary service markets.

While the exact details of the short-term wholesale market design in each area slightly varies, they all follow the three main steps [Fan et al., 2008, Al-Abdullah et al., 2016, Graf et al., 2020a, 2021, Wolak, 2021]: Day-ahead market, Reliability Unit Commitment, and Real-time market (see Figure 4).

In the day-ahead market (DAM), demand submit bids to purchase energy, while generation submit offers for energy and reserves. This market-clears produces generation and demand schedules (and the related nodal prices) compatible with all power system constraints, considering market participants offers. In the DAM, a Security Constrained Unit Commitment (SCUC) problem is solved to determine which generating units must be turned on for the next day, taking into account grid security constraints. The goal is to meet demand while minimizing costs and adhering to technical and security constraints.

After the DAM, the Reliability Unit Commitment (RUC) process is aimed at checking the compatibility of these schedules with ISO's forecasts for load and renewable energy. Unit commitment decisions can be taken in order to ensure the security of supply.

Finally, a real-time market is run (every five minutes) clearing the market using real-time actual data for clearing prices against submitted offers and determining real-time LMPs used also for clearing real-time imbalances against DAM schedules.

During the subsequent Deliverability Test, an Optimal Power Flow (OPF) problem is solved to determine the economic dispatch (SCED) and power flows across the network, respecting system constraints and the unit commitment decisions. This process generates an initial estimate of Locational Marginal Prices (LMPs), which reflect the cost of electricity at each network node. A contingency analysis is also performed, simulating unexpected events (e.g., line or plant failures) to ensure the system can operate securely under both N and N-1 conditions. In the Operator Review phase, system operators review the contingency analysis. If constraints need to be adjusted, previous Unit Commitment and Deliverability Test phases are rerun until dispatch solutions meet reliability and operational criteria (see Figure 5 for the whole day-ahead market process).

After the DAM, the Adjustment Period begins, during which market participants can modify their positions. During the adjustment period, a two-stage validation process is carried out because the solution obtained after the approval of the DAM, due to the approximations introduced by the use of DC-OPF, may not be implementable under the alternating-current model (AC-OPF).

Figure 6 illustrates the adjustment process that is executed after the close of the DAM to correct any violations or technical issues. In this phase, an AC-OPF problem is solved starting from the DAM solution in order to verify that no voltage issues are present. If the AC-OPF identifies criticalities of this kind, additional units are brought online through out-of-market actions.

Subsequently, an additional power-flow optimization with security constraints (PSC-OPF) is performed, ensuring that the system operates safely even under contingency or failure conditions. If the system successfully passes these stages, a dispatch solution is obtained that satisfies both the AC power-flow constraints (AC-feasible solution) and the N-1 security criteria (N-1 secure solution). This phase generates the new LMPs for each network node.

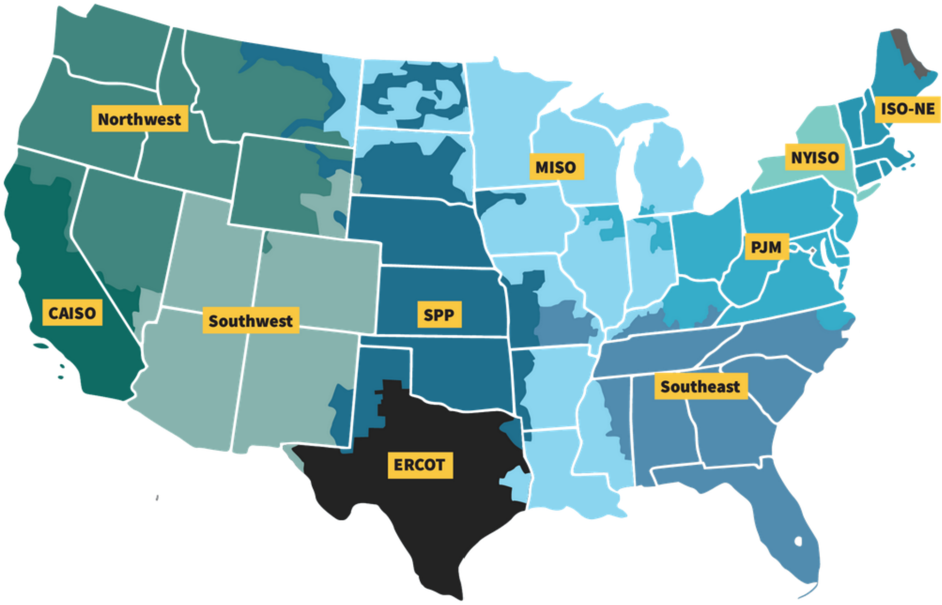
At the end of the adjustment period, the Real-Time Market (RTM) begins. During real-time operations, ISOs typically solve a Security-Constrained Economic Dispatch (SCED) problem.

All U.S. ISOs have adopted a soft constrained approach for clearing their short-term markets. The exact specification of those penalties is typically the result of a stakeholder process and changes over time as computational algorithms, risk tolerances, and resource mix changes. In the next sections we review the specifics of those penalty parameters in selected organized U.S. markets. A comprehensive overview of penalty parameters across ISOs can be found in Table 1.

5.1 California (CAISO)

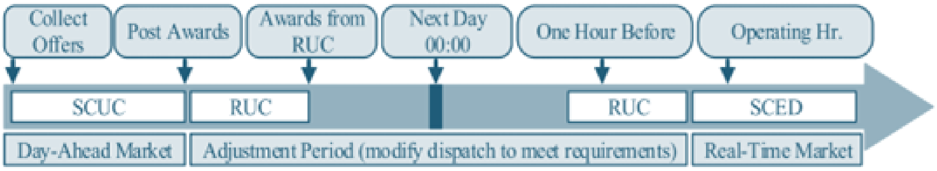
In the market architecture of the California Independent System Operator (CAISO), dispatch instructions and clearing prices are determined through a two-stage optimization process consisting of a scheduling run and a pricing run. The scheduling run establishes a physically feasible market solution by determining unit commitment and dispatch levels across all economic bids

Figure 3: Organized Wholesale Markets in the U.S.



Notes: Boundaries may have changed since the original publication. Source: Federal Energy Regulatory Commission (FERC) [2026].

Figure 4: Day-Ahead to Real-Time Market Process

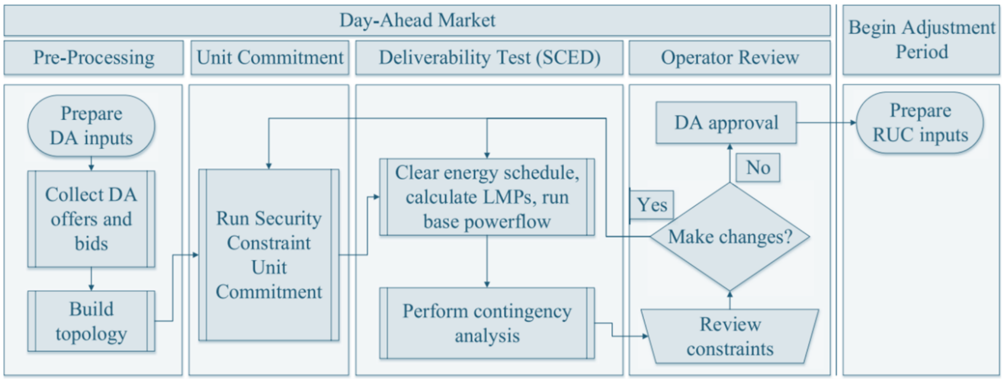


Source: Al-Abdullah et al. [2016].

and self-schedules. To do so, the algorithm relies on penalty prices, which function as artificial bids that assign relative priorities among constraints. These parameters discourage the violation of technical limits unless no economic solution is otherwise available. The pricing run then uses these results to produce economically meaningful Locational Marginal Prices.

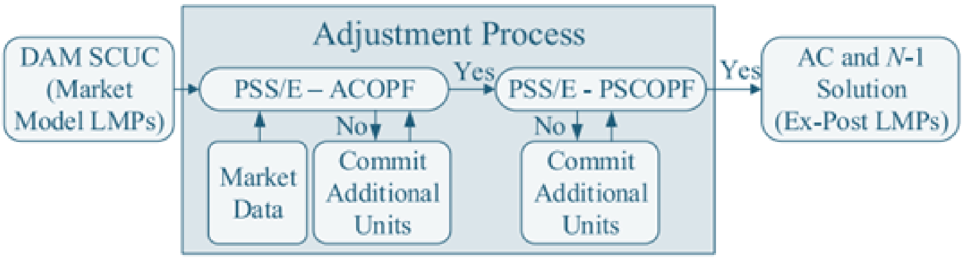
The values assigned to penalty prices differ substantially between the two runs, reflecting their distinct roles in grid reliability management and financial settlement. In the Integrated Forward Market (IFM), transmission constraints carry a scheduling run penalty of $5,000/MWh, while the pricing run value is set at $1,000/MWh. Power balance constraints, which ensure that supply meets demand, follow a similar tiered structure: under-generation is penalized at

Figure 5: Day-Ahead Market Process



Notes: High-level process overview. Source: Al-Abdullah et al. [2016].

Figure 6: Day-Ahead Market Adjustment Process



Notes: Two-stage adjustment process to obtain a feasible $N-1$ secure AC dispatch solution. Source: Al-Abdullah et al. [2016].

$4,900/MWh in the scheduling run and $1,000/MWh in the pricing run. For ancillary services, scheduling penalties for failing to meet minimum procurement requirements for Regulation Up, Spinning, and Non-Spinning reserves range from $2,200/MWh to $2,500/MWh, whereas the corresponding pricing run parameters are set at $250/MWh, rising to $1,000/MWh under specific sub-optimal conditions. In the Residual Unit Commitment (RUC) process, the power balance under-procurement penalty is $1,600/MWh for scheduling and $250/MWh for pricing, reflecting the different reliability thresholds applicable to the capacity market. Historically, these values have been set through an administrative process, with pricing run parameters anchored to and scaled from the prevailing bid cap, which usually is $1,000/MWh but can be increased up to $2,000/MWh in particular conditions [Fang et al., 2020, CAISO, 2020, 2024].

5.2 Midcontinent States (MISO)

The Midcontinent Independent System Operator (MISO) employs a structured set of penalty prices organized within demand curves to value constraint violations and guide price formation when operational requirements cannot be met through normal market dispatch. MISO penalty prices are organized in stepwise functions that assign a price to the violations of the constraints to their severity. In this framework, penalty prices constitute the individual steps of a demand curve: as a violation worsens, the curve activates progressively higher penalty prices, which in turn set the shadow price of the binding constraint and propagate through the Marginal Congestion Component (MCC) of nodal Locational Marginal Prices (LMPs), thereby translating a physical reliability need into an economic signal. These penalty prices are calibrated to reflect the economic cost of reliability shortfalls. For transmission constraints, specifically the Regional Directional Transfer (RDT) limit, the Transmission Constraint Demand Curve (TCDC) applies a lower step of $40/MWh at the modeled limit and a higher step of $500/MWh at 102 % of that limit. Operating reserve shortfalls carry distinct penalty structures by reservype: Short-Term Reserves (STR) reach a maximum of $500/MWh, spinning reserves are penalized at $65/MWh for shortages below 10% of the requirement and $98/MWh above that threshold, and the regulation curve averaged $139.76/MWh in 2024, being indexed to natural gas prices [Yang et al., 2019, MISO, 2024].

5.3 Texas (ERCOT)

The Electric Reliability Council of Texas (ERCOT) manages a wholesale electricity market that encompasses several interdependent clearing processes, among which the Day-Ahead Market (DAM) and the Real-Time Market (RTM) represent two central and complementary mechanisms. DAM is a voluntary, financially binding forward market that clears one day prior to the operating day, providing market participants with price certainty and enabling the system operator to establish a least-cost unit commitment plan. The RTM, on the other hand, operates in real time, executing every five minutes to dispatch online generation resources and maintain instantaneous power balance across the network. This fundamental difference in scope and timing is directly reflected in their respective penalty structures: because DAM must ensure a security-constrained feasible commitment plan for the following operating day, its penalty factors are set at significantly higher magnitudes, often in the millions of dollars, to enforce constraint satisfaction during the optimization. The RTM, by contrast, employs Shadow Price Caps to bound the cost of resolving real-time imbalances and congestion at more moderate levels.

In the RTM, the SCED algorithm applies transmission network Shadow Price Caps that vary by voltage level: \$5,251/MW for Base Case and voltage violations, \$4,500/MW for N-1 contingency violations on lines above 200 kV, \$3,500/MW for lines in the 100–200 kV range, and \$2,800/MW for lines below 100 kV. Power balance violations are handled through a graduated under-generation penalty curve that escalates with the magnitude of the mismatch: \$250/MWh for deviations up to 5 MW, rising through \$300/MWh, \$400/MWh, \$500/MWh, \$1,000/MWh, \$2,250/MWh, and \$4,500/MWh for progressively larger intervals up to 100 MW, after which the penalty reaches the High System-Wide Offer Cap (HCAP)[13] plus \$1/MWh. Over-generation imbalances are penalized at a fixed rate of −\$250/MWh.

The DAM penalty structure, by design, reflects the cost of commitment decisions and enforces a strict constraint hierarchy. Both over and under generation penalties are set at \$5,000,000/MWh, and Ancillary Service violations are penalized at the System-Wide Offer Cap (SWCAP),[14] with marginal reductions applied to Responsive Reserve (SWCAP −\$0.01/MWh) and Non-Spin (SWCAP −\$0.03/MWh), while Regulation Up/Down is penalized at the full SWCAP. Transmission network penalties in DAM are tiered by voltage level to prioritize enforcement of higher-voltage constraints: Base Case penalties range from 1050000\$/MW at 150+ kV down to \$350,000/MW for lines in the 1–10 kV range, with corresponding Contingency penalties set \$50,000/MW lower at each tier. Non-thermal generic constraints are assigned a uniform penalty of \$1,000,000/MW [ERCOT, 2024].

5.4 New York (NYISO)

The New York Independent System Operator (NYISO) employs a set of administrative penalty prices, referred to as Shortage Costs, within its scheduling and economic dispatch algorithms both in Day-Ahead and Real-Time. These prices act as upper bounds on the cost that the optimization

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[13] HCAP (*High System-Wide Offer Cap*) denotes the maximum system-wide offer cap established by the Public Utility Commission of Texas (PUCT).

[14] SWCAP (*System-Wide Offer Cap*) represents the maximum allowable cap on energy offers within the ERCOT market. The SWCAP is used to limit the Energy Offer Curves and to determine Ancillary Service penalty factors in the DAM

algorithm is willing to incur to resolve a constraint through corrective dispatch; if a constraint cannot be relieved at a cost below the associated penalty price, the system accepts a shortage and sets the energy price equal to the corresponding administrative value. Rather than functioning as simple penalties, these prices serve as market signals that reflect the economic value of system reliability and are designed to incentivize investment in flexible resources.

Transmission constraint penalties were substantially reformed with the introduction of the Constraint Specific Transmission Shortage Pricing (CSTSP) framework, which entered into force on 14 November 2023. Under this framework, penalty prices are linked to the Constraint Reliability Margin (CRM) assigned to each individual facility, which represents a capacity buffer between the modeled power flow and the physical limit of the network element. For facilities with a non-zero CRM, which constitute the majority of internal network elements, a six-step graduated demand curve (GTDC) is applied, where each of the first five steps covers a quantity equal to 20% of the facility's assigned CRM value. The six price levels are $200/MWh, $350/MWh, $600/MWh, $1,500/MWh, and $2,500/MWh for the first five steps respectively, with the sixth and final step set at $4,000/MWh, which activates for any violation exceeding the total assigned CRM. Standard CRM values assigned across the network reflect the degree of flow uncertainty associated with each facility type: 5 MW for most internal facilities that previously held a zero CRM, now governed by a simplified two-step curve introduced under CSTSP; 10 MW as the default for most 115 kV facilities within the New York Control Area (NYCA); 20 MW as the most widely used value and the default for facilities above 115 kV; 30 MW for specific structures on Long Island and in New York City exhibiting higher levels of unmodeled flows; 50 MW for critical facilities subject to elevated flow uncertainty; and 100 MW reserved for internal interfaces representing Interconnection Reliability Operating Limits (IROLs), where system condition uncertainty is greatest. Identified Facilities, internal structures that facilitate export flows from constrained areas, also carry a non-zero CRM but employ a simplified two-step pricing curve. External interfaces, which retain a CRM of 0 MW for consistency with NERC[15] standards, are subject to a single flat shadow price cap of $4000/MWh.

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[15] The North American Electric Reliability Corporation (NERC) is the regulatory authority responsible for developing and enforcing reliability standards for the bulk power system across North America. As a federally designated Electric Reliability Organization (ERO), NERC establishes mandatory operating and planning standards to which all balancing authorities and transmission operators, including NYISO, must strictly adhere in order to ensure the security and stability of the interconnected grid.

Operating reserve constraints are priced through Operating Reserve Demand Curves (ORDC), which vary by reserve type and geographic location. For the 30-minute NYCA-wide reserve requirement, a nine-step graduated curve is applied, scaling from \$40/MWh up to \$750/MWh depending on the severity of the shortage. The 10-minute total NYCA reserve carries a flat penalty of \$750/MWh, while both the 10-minute synchronous spinning reserve (10-Spin NYCA) and the 10-minute Eastern Area reserve are penalized at 775\$/MWh. For the South-East New York (SENY) subregion, the 30-minute reserve penalty is set at \$500/MWh for the base requirement and \$40/MWh for the incremental interval. Local reserves within New York City (NYC), covering both 10-minute and 30-minute products, are penalized at \$25/MWh each.

Regulation capacity shortfalls are priced through a multi-step curve: shortages below 25 MW are penalized at \$25/MWh, shortages between 25 MW and 80 MW at \$525/MWh, and shortages exceeding 80 MW at \$775/MWh. Power balance violations carry a maximum shadow price of \$4,000/MWh. Finally, under the Scarcity Pricing mechanism, if the activation of demand response programs—such as the Emergency Demand Response Program (EDRP) or the Special Case Resources (SCR) program—prevents a 30-minute reserve shortage, energy prices are administratively set at or above \$500/MWh, reflecting the system's proximity to a reliability emergency [Patton et al., 2024, NYISO, 2018].

5.5 New England States (ISO-NE)

ISO New England (ISO-NE) implements several penalty prices, also referred to as violation or constraint penalty factors, within its market clearing and dispatch algorithms to ensure feasibility of the optimization problem when operational constraints cannot be satisfied. These penalty prices are associated with specific system constraints and act as upper bounds on the shadow prices of the corresponding constraints.

For transmission constraints, the penalty factors depend on both the market time frame and the type of constraint. In the Day-Ahead market, violations of interface constraints are penalized at \$10,000/MWh, while violations of all other transmission constraints are penalized at \$30,000/MWh. In the Real-Time market, any transmission constraint violation is penalized at \$30,000/MWh. ISO-NE also defines a set of reserve constraint penalty factors applied when the system is unable to satisfy minimum operating reserve requirements. In Real-Time, the penalty for the Ten-Minute Reserve Requirement is set to $1,500/MWh, the Minimum Total Reserve Requirement is penalized at $1,000/MWh, the Zonal Reserve Requirement and the Total Reserve Requirement are both penalized at $250/MWh, and the Ten-Minute Spinning Reserve Requirement is penalized at $50/MWh. The Day-Ahead market adopts the same penalty values for the corresponding reserve constraints. An additional penalty price is associated with the Forecast Energy Requirement in the Day-Ahead market, which is set to $2,575/MWh and becomes binding when the co-optimization fails to procure sufficient energy and energy imbalance reserves to meet the ISO demand forecast.

The numerical values of these penalty prices are primarily determined through stakeholder negotiations and are periodically reassessed by ISO-NE in light of operational experience and expected market conditions [ISO-NE, 2025].

5.6 Southwest Power Pool (SPP)

In the Southwest Power Pool (SPP) Integrated Marketplace, Violation Relaxation Limits (VRLs) are administrative penalty parameters used to maintain feasible dispatch solutions when the Market Clearing Engine (MCE) encounters infeasible conditions in the Security-Constrained Economic Dispatch (SCED). VRLs assign penalty prices to selected operational constraints, allowing the optimization to relax constraint limits when necessary while preserving reliability signals in market prices. Specifically, when the shadow price of a constraint exceeds its predefined VRL, the constraint is relaxed and the shadow price is replaced by the corresponding penalty value. This mechanism ensures that the dispatch remains feasible while limiting extreme price outcomes and reflecting the economic cost of constraint violations.

SPP defines VRLs across five categories reflecting their relative operational priority. Resource Capacity constraints carry the highest penalty, which is $100,000/MW, to ensure that generating units remain within their dispatchable operating limits. The Global Power Balance constraint, which maintains equilibrium between total generation and load, has a VRL of $50,000/MW. Resource Ramp constraints, representing the physical ramping capability of resources within a dispatch interval, are assigned a penalty of $5,000/MW. Operating Constraints not subject to market-to-market (M2M) coordination, such as transmission limits identified through flowgates, manual entries, or Real-Time Contingency Analysis (RTCA), are associated with a uniform VRL of $1,500/MW for violations beyond 100% loading. In contrast, M2M constraints adopt the shadow price determined by the MISO under the relevant coordination agreements. Finally, the Regulation-Up plus Spinning Reserve requirement is associated with a VRL of $250/MW.

VRL values are reviewed annually through a sensitivity analysis. Using feed-forward dispatch simulations, SPP evaluates the impact of alternative penalty levels on key system indicators with the objective of identifying penalty levels that balance reliability enforcement and economic efficiency [Van Acker et al., 2012, SPP, 2025].

5.7 Pennsylvania-Jersey-Maryland Interconnection (PJM)

In the PJM wholesale electricity market, penalty prices represent the maximum cost the system is willing to incur to satisfy a constraint before declaring a violation. For transmission constraints, the default penalty factor in the day-ahead market dispatch run is $30,000/MWh, while both the day-ahead pricing run and the real-time market apply a lower default value of $2,000/MWh. PJM retains the authority to temporarily adjust these values for individual constraints.

Regarding operating reserve requirements, PJM employs a two-step Operating Reserve Demand Curve (ORDC) to price reserve shortages. The first step, associated with the Largest Single Contingency reliability requirement, carries a penalty factor of $850/MWh, while the second step, linked to an additional 190 MW reserve buffer, applies $300/MWh. Reserve clearing prices are subject to caps: synchronized reserves are capped at twice the first-step penalty factor ($1,700/MWh), non-synchronized reserves at 1.5 times ($1,275/MWh), and secondary reserves at once the penalty factor ($850/MWh) [PJM, 2025].

6 Conclusions

The combined analysis of the practices adopted by major transmission system operators in Europe and the U.S. provides a broad and comparative view of how technical constraints are managed within short-term market-clearing optimization models. In Europe, only a limited number of system operators employ advanced optimization tools such as unit commitment models, while most continue to rely on less integrated approaches. If hard constraints are used in those, they are typically complemented by flexible mechanisms to ensure the problem remains solvable (e.g., sequential constraint relaxation approach).

Soft constraints using (high) penalty values are an integral part of all organized short-term market mechanisms in the U.S. Penalty functions and constraint relaxation mechanisms are used across both unit commitment processes and real-time dispatch optimization capturing the trade-offs between system security and energy costs.

Constraint flexibility can reduce total operational costs and prevent situations where the market solution becomes infeasible, which would otherwise require manual backup procedures. However, special attention must be given to calibrating penalty parameters in a soft-constraint approach, as these values implicitly reflect the operator's risk tolerance and willingness to stress equipment, directly influencing both system security and economic outcomes. Although hard constraints are currently unsuitable for real-time or market-clearing applications, they may still serve a useful role in an analytical or ex-post context, for instance as benchmark references or diagnostic tools to assess system robustness and to compare alternative modeling assumptions.

More broadly, the use of penalties in soft-constraint formulations should not be interpreted as an improper simplification of the underlying optimization problem. On the contrary, it is precisely this relaxation mechanism that enables the adoption of more detailed and less approximated models—such as full security-constrained unit commitment formulations accounting for network constraints, ancillary service co-optimization, and intertemporal unit-level constraints—which would otherwise be computationally intractable within the time limits imposed by market operations and would have a high risk of infeasibility. Soft constraints thus represent a principled modeling choice that preserves an appropriate balance between problem feasibility and economic efficiency. Furthermore, it is worth emphasizing that the distinction between hard and soft constraints, while meaningful in a mathematical sense, does not map straightforwardly onto physical reality: constraints that are modeled as hard constraints in a market-clearing algorithm may still admit physical violations in real-time operations. For instance, thermal line limits are routinely subject to short-term overloads within equipment-defined emergency ratings, and system operators regularly manage such conditions through post-market corrective actions. The soft-constraint approach, when properly calibrated, provides a more transparent and economically grounded framework for reflecting these physical realities within the optimization.

A Penalty Prices Summary

Table 1: Summary of Penalty Values by Constraint Type Across U.S. ISOs/RTOs

ISO/RTO	**Constraint Type**	**Day-Ahead Market (DAM)**		**Real-Time Market (RTM)**
		Scheduling Run [$/MWh or $/MW]	**Pricing Run** [$/MWh or $/MW]	[$/MWh or $/MW]
CAISO	Transmission	5 000	1 000	N/A
	Power balance (under-generation)	4 900	1 000	N/A
	Ancillary services (Reg. Up / Spin / Non-Spin)	2 200–2 500	250–1 000	N/A
	RUC power balance	1 600	250	N/A
MISO	Transmission (RDT) – lower step	40		500
	Spinning reserves (shortage <10%)	—		65
	Spinning reserves (shortage ≥10%)	—		98
ERCOT	Power balance – DAM (over/under-generation)	5 000 000		N/A
	Transmission – DAM (≥150 kV, base case)	1 050 000		N/A
	Transmission – DAM (1–10 kV, base case)	350 000		N/A
	Transmission – RTM (>200 kV, N-1)	N/A		4 500
	Transmission – RTM (100–200 kV, N-1)	N/A		3 500
	Power balance – RTM (0–5 MW deviation)	N/A		250
NYISO	Transmission (CRM >0, step 6)	4 000		4 000
	Transmission (CRM >0, step 1)	200		200
	10-min. spinning reserve (NYCA)	—		775
	30-min. reserve (NYCA)	—		750
	Power balance	4 000		4 000
ISO-NE	Transmission (interface constraints)	10 000		N/A
	Transmission (all other)	30 000		30 000
	10-min. reserve requirement	1 500		1 500
	Total reserve requirement	1 000		1 000
SPP	Resource capacity	100 000		100 000
	Global power balance	50 000		50 000
	Operating constraints (non-M2M)	1 500		1 500
	Reg.-Up + spinning reserve	250		250
PJM	Transmission (dispatch run)	30 000	2 000	2 000
	Sync. reserves (ORDC step 1 cap)	850		1 700
	Non-sync. reserves (ORDC step 1 cap)	850		1 275
	Secondary reserves (ORDC step 1 cap)	850		850

Notes: N/A = not publicly specified or not applicable.

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