Price Formation Enhancements

Issue Paper

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Market & Infrastructure Policy

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1 Introduction

Price formation in organized electricity markets establishes market clearing prices for energy, ancillary services, and ramping products. How prices are set during conditions of scarcity is critical to appropriate price formation. Scarcity prices are important to attract supply and reduce demand during tight system conditions, and incentivize resources to be available and perform.

Recent energy shortages and associated prices in the ISO real-time market have emphasized the need for the ISO to review and enhance its scarcity pricing provisions. The ISO conducted a limited review of market scarcity provisions as part of its recent market enhancements for summer 2021 readiness policy initiative.[1] This initiative resulted in an enhancement that releases contingency reserves as energy at the energy bid cap price when there is insufficient supply to meet both energy and contingency reserve requirements. The real-time market may need further scarcity pricing changes to improve market price incentives during tight system conditions. Furthermore, energy storage capacity is rapidly growing across the ISO footprint. Changes to scarcity pricing in the real-time market may be necessary to help ensure state of charge and availability of these resources in the real-time market.

As part of evaluating issues related to price formation, some stakeholders suggest the ISO should reevaluate adoption of fast-start pricing, as has been implemented in other ISO/RTOs. The ISO previously examined this topic in response to FERC's 2016 NOPR addressing fast-start pricing.[2] Fast-start pricing makes it easier for fast-start resources to set market clearing prices and enables those prices to consider commitment costs.

Finally, there have been recent stakeholder discussions regarding how the multi-interval optimization in the real-time market dispatches storage resources. The function of the multi-interval optimization may result in frequent and costly uneconomic dispatches of storage resources. Changes to the multi-interval optimization could improve dispatch for storage resources. In addition, changes to real-time bid cost recovery could potentially be appropriate to compensate storage resources.

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[1] Market enhancements for summer 2021 readiness initiative: https://stakeholdercenter.caiso.com/StakeholderInitiatives/Market-enhancements-for-summer-2021-readiness.

[2] Fast-Start Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators, 81 Fed. Reg. 96,391 (Dec. 30, 2016), FERC Stats. & Regs. ¶ 32,720, at PP 3, 36-37 (2016) (NOPR).

The ISO plans to consider the following topics in this Price Formation initiative:

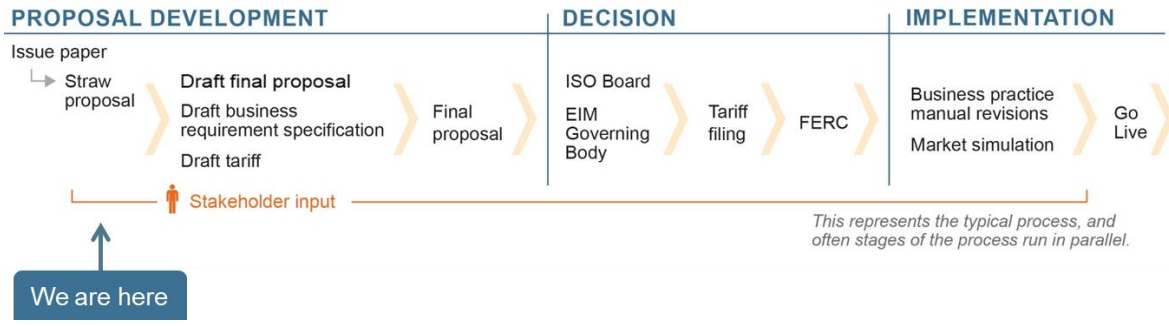
- Scarcity pricing enhancements;
- Fast-start pricing;
- The real-time market's multi-interval optimization, focusing on interaction with energy storage resources, and related changes to real-time bid cost recovery;
- BAA-level market power mitigation; and
- Other price formation issues as prioritized by the ISO or stakeholders.

2 Stakeholder Process

The ISO is at the "issue paper" stage in the price formation enhancements stakeholder initiative. Figure 1 below shows the status of the overall price formation enhancements stakeholder process.

The purpose of this issue paper is to identify and prioritize issues related to price formation in the ISO markets. After publication of the issue paper and an initial stakeholder call and feedback, the ISO will hold workshops as necessary to engage stakeholders in the policy design process on prioritized topics. As appropriate, the ISO may organize focused working groups to discuss issues of a complex nature. The ISO will publish one or more straw proposal(s) following the issue paper to restate and clarify the prioritized issues based on stakeholder feedback, and propose solutions to the identified issues and concerns.

Figure 1: Stakeholder Process Timeline



2.1 June 9, 2022 Stakeholder Workshop

The ISO hosted a stakeholder workshop on June 9, 2022 on the topic of price formation.[3] The ISO solicited stakeholders in advance to prepare materials and present their organization's perspective on the topics scoped for this initiative. Five entities made presentations, as summarized below:

- **California ISO** presented on the intended purpose of the stakeholder initiative and the preliminary scope;
- **Powerex** presented their perspectives with a focus on fast-start pricing, and provided a report (prepared with the Public Power Council and EnergyGPS) detailing the importance of fast-start pricing in market design;
- **Calpine** presented their perspectives with a focus on scarcity pricing, and provided a report (prepared with GDS Associates) detailing issues and recommendations for scarcity pricing market design;
- **Rev Renewables** presented their perspectives with a focus on battery storage interaction with the real-time market's multi-interval optimization;
- **WPTF** presented a summary of their perspectives on each topic and their perspective on how the ISO should prioritize each issue.

In addition to these presentations, stakeholders had the opportunity to ask ISO staff whether the ISO would consider certain topics or issues as part of this initiative. Stakeholders will have an additional opportunity to recommend and justify the inclusion of other price formation issues in their comments to this Issue Paper. However, the ISO provides its current perspective on the topics that stakeholders brought up at the workshop:

- **Integrated BAA pricing:** Integrated BAAs (IBAAs) are not part of the ISO BAA but are closely integrated/interconnected with the ISO's system. The ISO market uniquely models and prices interchange transactions with IBAAs. The ISO does not intend to address price formation related specifically to IBAAs in this initiative. The ISO presumes that IBAA functionality will no longer be relevant when entities participate in a regional day-ahead market.

[3] Stakeholders can find all workshop materials, including presentations and related reports, on the initiative webpage - https://stakeholdercenter.caiso.com/StakeholderInitiatives/Price-formation-enhancements.

- **Decremental market power mitigation:** The ISO does not intend to address decremental market power mitigation in this initiative. The ISO plans to consider this topic in the upcoming VER Dispatch Enhancements initiative currently scheduled to begin in Q2 2023.[4]
- **Pumped storage** – the ISO does not intend to address price formation issues related specifically to market participation of pumped storage resources in this initiative but stakeholders are welcome to elaborate in their comments if there are price formation issues specific to pumped storage resources the ISO should consider.
- **Market-based commitment cost bids** – the ISO does not intend to consider market-based commitment cost bids in this initiative.
- **Reliability demand response resource** – the ISO does not intend to address price formation issues related to reliability demand response resources in this initiative but acknowledges the ISO will need to consider how scarcity pricing or fast-start pricing proposals affect RDRRs. Stakeholders are welcome to elaborate in their comments if there are price formation issues specific to RDRRs the ISO should consider.

3 Price Formation Enhancements Scope

3.1 Scarcity Pricing Enhancements

Price formation is the process that determines prices for energy, ancillary services, and ramping products that market participants buy and sell through the market. Part of price formation is how to establish and set prices when there is insufficient supply to cover the energy, ancillary services, or ramping product requirements. This is referred to as "scarcity pricing".

Rather than resource energy offers, the ISO uses administrative values to set prices during scarcity conditions in the day-ahead and real-time markets. The ISO markets use a scarcity reserve demand curve with additive penalty factors to reflect the degree of shortage and are organized so the market is deficient in the lowest quality reserve services first.

[4] See Final Policy Initiatives Roadmap 2022 -2024 - http://www.caiso.com/InitiativeDocuments/FinalPolicyInitiativesRoadmap2022-2024.pdf.

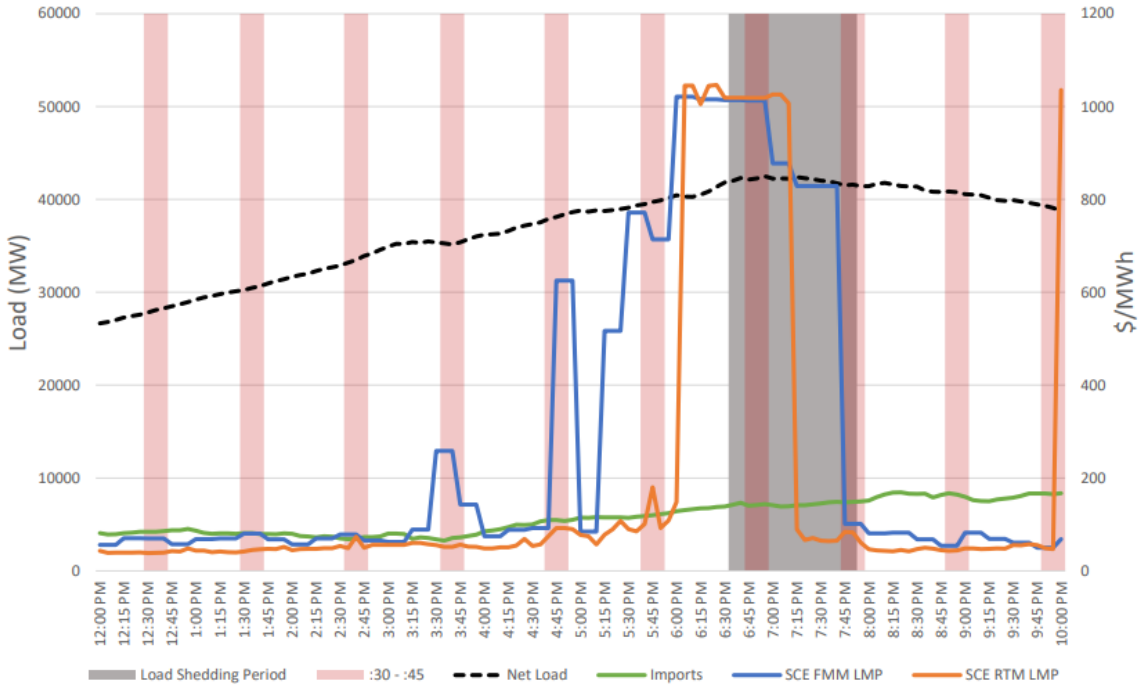
Efficient scarcity pricing helps to maintain system reliability by sending price signals that reflect scarce conditions. Penalty prices should be sufficiently high to incentivize performance of scheduled resources and induce availability of resources (including imports) to the maximum extent possible. A high price signal also aligns with the high value a majority of consumers place on avoiding involuntary load shedding.

The August 2020 heat wave and outages[5] prompted the CAISO to review its scarcity pricing market design. Market Surveillance Committee (MSC) member Scott Harvey gave a presentation at the December 2020 MSC meeting discussing scarcity pricing designs in other ISOs and associated trends[6]. On slide 7, Harvey writes, "It is not clear what occurred on August 14 to allow prices to be set at levels that did not reflect a power balance violation when the CAISO was in a stage 2 emergency and presumably therefore short of reserves." To illustrate this point, Figure 2 shows the 15-minute (blue line) and 5-minute (orange line) real-time energy prices within the SCE DLAP on August 14, 2020. Both the 5-minute and 15-minute energy prices plummeted from near the energy bid cap ($1000/MWh) to around $100/MWh during the load shedding period (shaded grey).

[5] See Final Root Cause Analysis: Mid-August 2020 Extreme Heat Wave - http://www.caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf.

[6] See Market Surveillance Committee Scarcity pricing background discussion - http://www.caiso.com/Documents/ScarcityPricingBackgroundDiscussionHarvey-Presentation-Dec11_2020.pdf

Figure 2: Market Pricing during Load Shedding Event – August 14, 2020



Source: Market Surveillance Committee Scarcity pricing background discussion, slide 8

The following sections summarize how existing scarcity pricing measures work in the CAISO markets.

3.1.1 *Existing Scarcity Pricing Measures*

Energy

The ISO's real-time market clears energy schedules using supply bids and the demand forecast. When there is insufficient supply of energy offers or ramping capability, the market will relax the power balance constraint and set energy prices at the penalty price for violating the power balance constraint.

The ISO has implemented several recent changes related to energy scarcity pricing. In 2020, the ISO began an initiative to address the requirements stipulated in FERC Order 831.[7] This initiative resulted in the ISO increasing the energy bid cap and power balance constraint penalty price in the pricing run from $1,000/MWh to $2,000/MWh

[7] FERC Order 831 – Import bidding and market parameters stakeholder initiative. https://stakeholdercenter.caiso.com/StakeholderInitiatives/FERC-Order-831-Import-bidding-and-market-parameters.

when certain conditions are met.[8] The ISO also developed in this initiative a methodology for allowing energy bids above $1,000/MWh with requirements that non-import resource-specific resources bidding above $1,000/MWh justify their costs. The ISO also implemented a scarcity pricing change in its market enhancements for summer 2021 readiness stakeholder initiative.[9] This initiative resulted in the ISO including energy from generation the ISO releases from contingency reserve to serve load in the bid stack with a bid price equal to the market's applicable energy bid cap.

Ancillary Services

The ISO procures ancillary services (i.e., regulation up, regulation down, spinning reserves, and non-spinning reserves) to meet applicable reliability criteria.

The ISO procures 100% of its ancillary service needs in the day-ahead market and may procure incremental reserves in the real-time market if they are needed.[10] The ISO sets procurement targets for ancillary services within various defined ancillary service regions or sub-regions. The ISO markets allow for cascading procurement of the upward ancillary services where higher quality products can satisfy the requirement of lower quality products (i.e., regulation up can count as spinning and non-spinning reserves, and spinning reserves can count for non-spinning reserves), when it is economic to do so.

Whenever there is insufficient supply to meet minimum ancillary service procurement requirements in a region or sub-region, the CAISO uses a tiered demand curve to set administrative values for ancillary service prices. The tiers allow prices to rise incrementally at increasing levels of scarcity.

Table 1 shows the scarcity reserve demand curve incorporated in the CAISO market.[11] Regulation up and spinning reserves have a fixed shortage price whereas non-spinning reserves and regulation down have stepped penalties that increase as the reserve

[8] Condition 1) A cost verified energy bid is submitted from a resource-specific resource over $1,000/MWh; or Condition 2) the ISO-calculated Maximum Import Bid Price is over $1,000/MWh.

[9] Ibid. See reference 1.

[10] Incremental ancillary services can be procured in the hour-ahead scheduling process and the fifteen-minute market, but not in the five-minute market. Only incremental ancillary services are co-optimized with energy in the real-time market; ancillary services procured in the day-ahead market are not re-optimized.

[11] Note that CAISO Tariff section 27.1.2.3.5 has a separate table with different values when the hard offer cap is in effect.

deficiency worsens. For example, if the market is up to 70 megawatts short of regulation, spinning reserve, and non-spinning reserve offers to meet the non-spinning reserve requirement, the market will forego procurement of non-spinning reserves at a cost of $500/MWh. Because ancillary service procurement is cascading, if the market is short of the spinning reserve or regulation up requirements, the market will procure incremental costs of $100/MWh and $200/MWh respectively (in addition to the penalty of violating the non-spinning reserve requirement) such that a shortage in all three ancillary services would be priced at $1000/MWh.

Table 1: Scarcity Reserve Demand Curve

Reserve	Demand Curve Value ($/MWh)					
	Percent of Max Energy Bid Price		Max Energy Bid Price = $750/MWh		Max Energy Bid Price = $1000/MWh	
	Expanded System Region	System Region and Sub-Region	Expanded System Region	System Region and Sub-Region	Expanded System Region	System Region and Sub-Region
Regulation Up	20%	20%	$150	$150	$200	$200
Spinning	10%	10%	$75	$75	$100	$100
Non-Spinning						
Shortage > 210 MW	70%	70%	$525	$525	$700	$700
Shortage > 70 & < = 210 MW	60%	60%	$450	$450	$600	$600
Shortage □ 70 MW	50%	50%	$375	$375	$500	$500
Upward Sum	**100%**	**100%**	**$750**	**$750**	**$1,000**	**$1,000**
Regulation Down						
Shortage > 84 MW	70%	70%	$525	$525	$700	$700
Shortage > 32 & < □ 84 MW	60%	60%	$450	$450	$600	$600
Shortage □ 32 MW	50%	50%	$375	$375	$500	$500

Source: California ISO Business Practice Manual for Market Operations Version 79, page 181 and CAISO Tariff section 27.1.2.3.5.

Ancillary service scarcity may or may not affect energy prices. In the integrated forward market or fifteen-minute market, the price of energy will include the opportunity cost of the scarce ancillary service if the market backs down a resource's ancillary service schedule to provide an additional MW of energy. The price of energy will not change

when there are sufficient energy offers to meet energy demand, but insufficient AS offers to meet AS requirements.[12]

Ramping Products

The real-time market procures flexible ramping product using a demand curve to meet the upper (upward) and lower (downward) flexible ramping uncertainty requirements. The flexible ramping product demand curve establishes the price of not fulfilling the flexible ramping requirement for a given interval. The market will procure flexible ramping product up to the full requirement as long as the energy price is lower than the cost of not fulfilling the flexible ramping requirement for a given interval. When the energy price is above the expected cost of not meeting the flexible ramping uncertainty requirement, then the market will procure no additional flexible ramping product. The cost of not fulfilling the flexible ramping requirement is based on a demand curve. The ISO calculates the demand curve based on the probability of violating the power balance constraint if the market did not procure additional flexible ramping product. For example, if there were a 10% chance of violating the power balance constraint, the market would not procure flexible ramping product at a price above $100/MWh.[13]

The price cap for the flexible ramp up demand curve is administratively set to $247/MWh, which is just below the pricing run penalty prices for the ancillary services procurement constraint, which range from $248 to $250/MWh.[14] The real-time market will go short on flexible ramping product before any of the ancillary services.

3.1.2 *Scarcity Pricing Issues*

Current energy bid caps may not provide appropriate incentives for market participants during tight system conditions

The ISO market currently caps energy prices at either $1,000/MWh or $2,000/MWh, depending on whether the soft or hard offer cap is in effect. In most cases, the offer caps and price caps in effect during the day-ahead market are the same as the real-time market. This means that market participants face little downside price risk during tight system conditions when market participants expect day-ahead energy prices to be near

[12] In the case where a lack of ancillary service offers drives ancillary service scarcity, while at the same time there are plenty of energy offers to meet energy demand, the ancillary service shortage prices are not reflected in energy prices because there is no opportunity cost.

[13] $1000/MWh energy bid cap price * 10% probability = $100/MWh

[14] The pricing run penalty prices for relaxing ancillary service procurement constraints are used in the market optimization to maintain the scheduling priority in the pricing run,

the cap. This creates perverse market incentives for a variety of market participants that are not aligned with reliable system operations during tight supply conditions. For example:

- Load faces little price risk when day-ahead energy prices clear near the bid cap. This creates an incentive for load serving entities to under-schedule their load and wait for the real-time market to secure supply. Under-scheduled load was cited as one of the contributing factors to the August 2020 load shedding events.[15] Accurate load scheduling is needed in tight supply conditions to ensure sufficient supply is secured in preparation for real-time conditions.
- Resources scheduled for energy in the day-ahead market face little price risk when day-ahead prices clear near the bid cap if their supply is unavailable in real-time. Unavailable supply can exacerbate or trigger real-time scarcity conditions but suppliers are not penalized commensurate with the harm they cause.
- Convergence bidders face improper incentives when day-ahead energy prices clear near the bid cap. Virtual supply faces limited loss potential and virtual demand faces limited gain potential, which changes the calculus for convergence bidding profits in a way that is contrary to their purpose and harms their ability to converge market prices and outcomes.
- Energy storage resources can be optimally scheduled in the day-ahead market (charged in the middle of the day during high solar output and discharged during the net load peak). However, without real-time scarcity pricing, storage resources may not have sufficient incentive to meet their day-ahead schedule if there are high energy prices in real-time prior to the net load peak.

Pricing Ancillary Service Shortages

Ancillary service scarcity pricing is not fully effective in setting scarcity prices in the ISO market for several reasons. The ISO only procures incremental ancillary services in the real-time market if the amount procured in the day-ahead market is not sufficient to meet requirements. In addition, the CAISO does not re-optimize ancillary services with energy in all market intervals. For this reason, ancillary services scarcity prices do not always occur in tight conditions. In addition, the CAISO only procures ancillary services in the fifteen-minute market and not the five-minute market. As a result, ancillary services scarcity pricing in the real-time market only affects fifteen-minute market

[15] Ibid. See reference 5.

prices and not five-minute prices. Finally, the Western Energy Imbalance Market does not currently include ancillary services. Consequently, ancillary services shortage pricing does not affect scarcity pricing in balancing authority areas other than the CAISO.

To make ancillary service scarcity pricing more effective in setting prices, the real-time market would have to re-optimize ancillary services with energy in all real-time market intervals, not just when the real-time market must procure additional ancillary services. This is likely not practical because the market does not model the deliverability of ancillary services at a more granular level than by ancillary service region. ISO operations needs to begin its review of the deliverability of awarded ancillary services in the day-ahead timeframe. It would not be feasible for them to review awarded ancillary services after every real-time dispatch cycle.

One potential option to enhance the CAISO's shortage pricing without re-optimizing ancillary services may be to increase the penalty prices of both flexible ramping product and ancillary services from around $250/MWh to a value closer to the $1,000/MWh penalty price for violating the power balance constraint. This would allow prices to rise more gradually to the $1,000/MWh power balance constraint penalty price in tight supply conditions because the market would relax the flexible ramping product procurement constraint in scarce conditions. If the flexible ramping product demand curve had a higher maximum price than the current $247/MWh, these higher prices would be reflected in energy prices as the market forgoes greater flexible ramping product procurement. This would also allow prices to rise gradually as the ISO approaches scarcity conditions rather than waiting for an actual shortage condition to trigger scarcity pricing, which would allow the ISO market to attract more imports and other supply offers when the ISO balancing authority area most needs them.

3.2 Consideration of Fast-Start Pricing

As the ISO and other entities explore broader regional market participation with a more diverse resource fleet and additional operational considerations, the ISO believes it is appropriate to reassess its initial position regarding the need for fast-start pricing in the markets it administers. A regional market will result in significant changes in the composition of the generation fleet, which may necessitate changes to the ISO's operational requirements. While the ISO still has the concerns set out in responses to the FERC NOPR, as described below, the ISO remains open to the possibility that fast start pricing could result in prices that more accurately reflect system marginal costs in a regional market context. In this initiative, the ISO will be looking at what pricing enhancements it can make to best reflect marginal costs and meet the operational needs of the system.

3.2.1 *FERC NOPR on Fast-Start Pricing*

In December 2016, the Federal Energy Regulatory Commission (FERC) issued a notice of proposed rulemaking (NOPR) in Docket RM17-3 to require each RTO/ISO to adopt market rules meeting certain requirements for pricing fast-start resources.[16] In the NOPR, FERC noted that fast-start pricing methods vary but intend to "recognize that fast-start resources are…the marginal resource used to meet the next increment of energy or operating reserves demand."[17] The two commonly shared components of fast-start pricing, both as applied and as discussed in the NOPR, are:

1. **Minimum output limit relaxation** – the market considers a resource as dispatchable over its entire range by relaxing its lower operating limit (Pmin) down to 0. This makes it easier for the resource to be the "marginal generator" and set the price.[18]
2. **Inclusion of commitment costs in pricing** – the market incorporates start-up and minimum load costs directly into the locational marginal prices.

However, each ISO/RTO uses different optimization formulations to clear their real-time markets. For example, the CAISO's real-time market is unique among other ISO/RTOs in that it employs both a multi-interval economic dispatch and a flexible ramping product. Different fast-start pricing formulations mean that, faced with the same operating situations, different ISOs will formulate different market dispatch and prices based on the design of their real-time market optimization. Each ISO/RTO needs to take into account its unique circumstances and recognize the benefit of fast-start pricing to its market price formation depends on its resource fleet, system conditions, and real-time market algorithms.

In response to that FERC NOPR, the ISO filed comments expressing concern with FERC's proposed rule and its requirements for relaxing economic minimum operating limits and incorporating commitment costs into prices for fast-start resources.[19] The ISO argued that while prices should fully compensate resources for the marginal cost of providing a

16 Fast-Start Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators, 157 FERC ¶ 61,213 (2016).

17 Ibid.

18 Note this only incurs in the market's pricing process, not its scheduling process, to ensure the market schedules respect the resource's actual operating constraints.

19 ISO Comments dated February 28, 2017 filed in RM17-3; see also ISO Supplemental Comments dated August 17, 2017.

particular service, applying such a rule in the ISO's markets would promote the wrong incentives and undermine the ISO's efforts to address the current operational challenges in its markets, including the need for more flexible resources in real-time. Specifically, the ISO argued that relaxing the economic minimum operating limit of a fast-start resource to zero could create infeasible dispatches and potentially undermine accurate price signals arising from how the ISO's flexible ramping product dispatches and compensates resources to address ramping requirements between two successive real-time market intervals. That is because fast-start pricing considers units as dispatchable below their Pmin, so the market may see no need to dispatch units out of their merit order to secure the ramp needed to meet the net load or the net load uncertainty in a future interval.[20] As a result, the market does not price the opportunity cost of ramp and does not compensate resources for their flexibility to provide ramp.

FERC ultimately withdrew its NOPR to adopt a uniform fast-start pricing rule for RTOs/ISOs and terminated the rulemaking proceeding.[21]

3.2.2 *Fast-Start Pricing Practices of Other ISO/RTOs*

Despite the commonly shared components of fast-start pricing described in the section above, ISO/RTOs vary in the implementation details. Appendix B provides a summary of the fast-start pricing policies of various ISO/RTOs but the major distinguishing characteristics are:

- The definition of a "fast-start resource", differentiated by start-up and minimum run times, and the exclusion of certain resource types;
- The methods for incorporating commitment costs (start-up and minimum load costs[22]) into price, for example, by incorporating amortized commitment costs as incremental to the energy bid curve, or by using "integer relaxation" of the binary unit commitment variable;
- Whether and how offline resources are included in fast-start pricing logic;

[20] For numerical examples, see Attachment B of ISO Supplemental Comments dated August 17, 2017 filed in RM17-3. https://www.caiso.com/Documents/Aug18_2017_SupplementalComments-Fast-StartPricingNOPR_RM17-3.pdf.

[21] Fast-Start Pricing in Markets Operated by Regional Transmission Organizations and Independent System Operators, 161 FERC ¶ 61,293 (2017)

[22] Can also be referred to as "no-load costs".

- Whether fast-start pricing logic is included in both day-ahead and real-time markets, or just the real-time market;
- Whether to impose opportunity costs payments or financial penalties to incentivize generators not to deviate from their dispatch.

3.2.3 *Constrained Output Generators*

Although not implemented in response to the FERC NOPR, the ISO does have functionality that enables the market to model a limited set of resources differently for pricing purposes. The ISO calls these resources Constrained Output Generators (COGs). A Constrained Output Generator is a resource with a zero or very small operating range between its minimum load (Pmin) and maximum capacity (Pmax).[23] Resources with zero operating range must participate as COGs and any other resource that meets the criteria to be a COG can voluntarily elect for the market to treat them as such.[24] The market treats COGs as fully dispatchable from 0 to their Pmax in both the day-ahead and real-time. This allows COGs to set the price. The ISO calculates a COGs energy bid by dividing its minimum load cost by the MW quantity of the resource's Pmax.

3.3 Multi-Interval Optimization

In previous initiatives stakeholders noted that multi-interval optimization in the real-time market could result in uneconomic dispatch instructions for energy storage resources. For example, the ISO may dispatch a storage resource to discharge during a specific real-time interval, even when that resource's discharge bid is above the current prevailing price during that interval because of economic charging opportunities in advisory intervals. Similarly, the ISO may uneconomically dispatch a storage resource to charge because of economic discharging opportunities in advisory intervals. The outcomes in these examples may be the result of the multi-interval optimization in the real-time market and energy storage resources' unique ability to charge or discharge in earlier intervals in anticipation of future awards in the opposite direction.

The ISO dispatches resources optimally across a single financially binding 5-minute interval and 12 additional advisory 5-minute intervals in the real-time dispatch (RTD) market. The successive run for the real-time market considers the first advisory 5-minute interval in the initial run as the financially binding interval, and all advisory

[23] A COG's operating range (Pmax – Pmin) is less than 3 MW or 5 percent of their actual Pmax, whichever is higher.

[24] There are currently no COGs registered in Master File.

intervals move forward one increment. The market issues optimal dispatch instructions to all resources in order to minimize aggregate costs to serve load during all intervals, binding and advisory. The optimization includes identical weighting – and contribution to aggregate costs – for each market interval.

At one extreme, the ISO could consider eliminating the multi-interval optimization. The ISO discussed this as a potential option at the October 2021 Market Surveillance Committee meeting.[25] The original intent of the multi-interval optimization was to ensure that all resources on the grid are operating in a way that will enable the resource mix to serve load in the future advisory intervals. This includes having enough ramp capability and ability to provide energy to serve load while considering active constraints and grid topology. The multi-interval optimization process ensures that the market starts and/or positions appropriately to meet anticipated future needs of the grid.

The same operational challenges that initially prompted the ISO to develop the multi-interval optimization still exist today. Thus, removing this product completely may not be feasible for the ISO – with a principle objective to maintain reliable grid operations. This was a primary component of the ISO's presentation at the October market surveillance meeting.

At the October Market Surveillance Committee, LS Power/Rev Renewables proposed removing storage resources from the multi-interval optimization. Implementing a solution like this may involve limiting resources that the multi-interval optimization could potentially dispatch during advisory intervals. Specifically, the ISO could preclude the market software from sending dispatch instructions to storage or other use-limited resources in future advisory intervals. This functionality could be something that resources opt into and would not be a standard treatment for all resources that are eligible.

Potential market changes like these may resolve concerns about uneconomic dispatch to resources during specific intervals but can potentially introduce other issues. For example, future advisory market solutions may not be optimal because the market software does not have visibility into all available resources. In turn, this could result in sub-optimal schedules for the binding interval. The ISO also notes that storage resources, or other use-limited resources, are not the only resource types the market could uneconomically dispatch because of anticipated future conditions. The ISO must

[25] Market Surveillance Committee meeting, October 1, 2021: http://www.caiso.com/Documents/EnergyStorageEnhancementsMIO-Presentation-Oct1_2021.pdf.

carefully consider how and if treatment should be applied to other resource types as well as storage.

Stakeholders have suggested ISO could consider placing additional weight on the binding intervals, compared to the advisory intervals, or placing additional weight on the early advisory intervals rather than the later advisory intervals to help address dispatch instructions that appear uneconomic for the binding interval. The ISO seeks further detail on this approach in stakeholder comments. As with other potential solutions, the ISO would have to consider fully the impact this change would have on the efficient operation of the grid and the ability for the market to position resources in an optimal way to meet anticipated grid conditions.

Another potential solution noted by LS Power/Rev Renewables is simply to award a resource bid cost recovery so that the resource is made financially whole in the real-time market if it is dispatched uneconomically in real-time. The ISO discusses this proposal in the next section.

3.4 Bid Cost Recovery

3.4.1 *Uneconomic Dispatch*

As noted in the previous section, market participants have advocated for bid cost recovery changes for storage resources to compensate them for uneconomic dispatch instructions driven by advisory conditions that do not materialize. The ISO discussed this topic at the October 2021 Market Surveillance Committee meeting and outlined cases when this occurred for storage resources. Specifically, the ISO noted that scenarios may occur when future advisory prices are high and a storage resource is uneconomically scheduled to charge in the binding interval but high advisory prices do not materialize, or when future advisory prices are low and a storage resource is uneconomically scheduled to discharge in the binding interval but low advisory prices do not materialize.

To address these concerns, LS Power/Rev Renewables recommended changes to bid cost recovery rules for storage resources, which would consider settlements under a counterfactual dispatch based on energy awarded strictly based on bids and binding interval prices. This type of modification would significantly change the existing bid cost recovery paradigm. Today, bid cost recovery is based on total overall bid costs compared market revenues received for dispatch instructions netted over a 24-hour period. The ISO awards bid cost recovery only if there are net shortfalls across all 24 hours.

In previous discussions, stakeholders suggested that these changes to bid cost recovery might only apply to storage resources because of their unique operating characteristics. If adopted, however, the ISO will need to determine which resources these new rules apply to and provide a holistic picture of how bid cost recovery will work for all resources in the ISO markets. Storage resources are not the only resource types that could potentially be dispatched sub-optimally because of anticipated future conditions, and these may be considered in this initiative as well.

3.4.2 *Performance Incentives*

The ISO calculates bid cost recovery independently for the day-ahead and real-time markets. Resources could receive rents in the day-ahead market but may have schedules in the real-time market that that include losses from buying back infeasible day-ahead schedules. In these cases, resources can largely retain day-ahead rents through real-time bid cost recovery.

In Section 3.1 the ISO notes that one objective of adjusting scarcity pricing in the real-time market could be to incentivize storage resources to meet day-ahead schedules. The current bid cost recovery rules may prevent scarcity prices alone from being an effective incentive to ensure resources can meet day-ahead schedules. The ISO must carefully consider the interplay between uplift mechanisms and changes to penalty parameters prior to implementing the price formation policy.

3.5 Market Power Mitigation

Today the ISO performs a dynamic competitive path assessment (DCPA) to test if three or fewer entities can provide 'pivotal supply' and effectively affect prices through withholding. This assessment accounts for the total amount of generation in a constrained area and compares that value to the demand in the same area. If three or fewer suppliers own the residual supply (i.e., the supply in excess of the demand), the assessment fails. Failing the assessment means that three of fewer sellers may have the ability to influence prices and could set them at arbitrarily high levels and extract rents if no further action is taken.

When the assessment fails, suppliers within the constrained area are subject to market power mitigation. The ISO performs market power mitigation on a resource-by-resource basis and compares bids provided by suppliers with ISO-generated default energy bids (DEBs). Default energy bids represent what the ISO believes the marginal cost for a resource is, which can include fuel costs, opportunity costs, and a variety of adders representing costs. When the assessment fails, the ISO will replace bids

provided by suppliers and re-run the market optimization with the updated bid curves if the bids provided by suppliers are greater than the resource's default energy bid.

The ISO discussed two potential changes to the market power mitigation framework in the extended day-ahead market (EDAM) initiative.[26] Market participants suggested that the ISO consider discussions to changes for market power mitigation in this initiative instead. The ISO is proposing the changes below in response to that feedback. The first change involves grouping balancing authority areas together when performing market power mitigation tests. The second change updates the dynamic competitive path assessment so that all constraints impacted by a resource are considered instead of only those within the same balancing authority area.

3.5.1 *Balancing Authority Area Grouping*

The ISO proposes updating the market power mitigation methodology to group multiple balancing authority areas together when performing the dynamic competitive path assessment. An approach like this may be more appropriate as the ISO expands the day-ahead footprint to other balancing authority areas.

Today, prices can diverge between balancing authority areas when there is congestion along the paths that connect them. Congestion into a specific balancing authority area results in higher prices compared to prices in the balancing authority area where the path originates. These price differences are reflected in the power balance constraint shadow prices for each of the balancing authority areas.

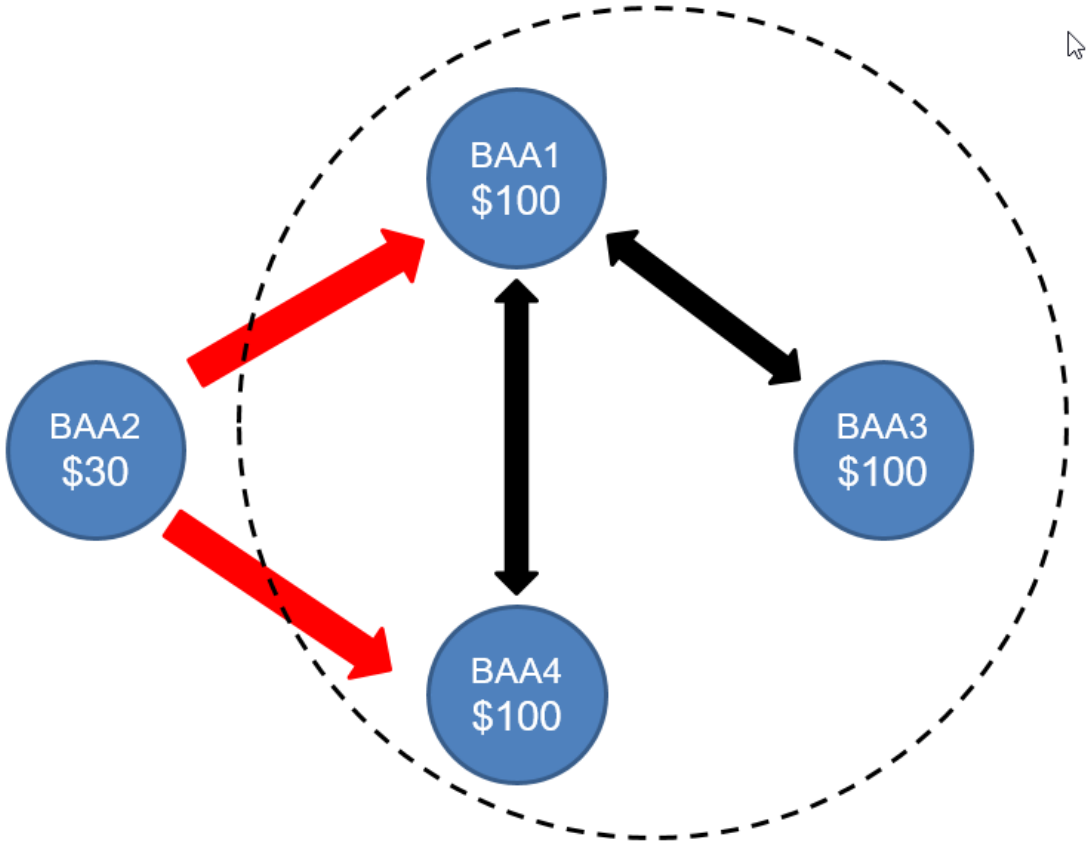
Sometimes groups of balancing authority areas experience congestion from the group to other balancing authority areas. This results in the same price for each of the balancing authority areas within the group but different prices for balancing authority areas outside of the group. In this scenario, there is no transmission congestion between the balancing authority areas in the same group. The current market power mitigation process considers dynamic competitive path assessments independently for each balancing authority area even though there may be competitive supply across a group of balancing authority areas.

Figure 3 illustrates this concept. In this simplified hypothetical scenario, balancing authority areas 1, 3 and 4 have prices that are elevated above those in the neighboring balancing authority area 2. There is no congestion between balancing authority areas 1, 3 and 4 but there is congestion between that group of balancing authority areas and the

[26] Extended Day-Ahead Market initiative, https://stakeholdercenter.caiso.com/StakeholderInitiatives/Extended-day-ahead-market.

paths leading from balancing authority area 2. In this situation, the current market power mitigation rules will perform dynamic completive path assessments for balancing authority area 1, 3 and 4 independently. This could potentially result in one, two or even all three of these areas failing the assessment and being subject to market power mitigation. In this situation, the ISO proposes that a single test be carried out for all of the supply in balancing authority areas 1, 3 and 4, instead of three independent tests.

Figure 3: Simple BAA Grouping Scenario

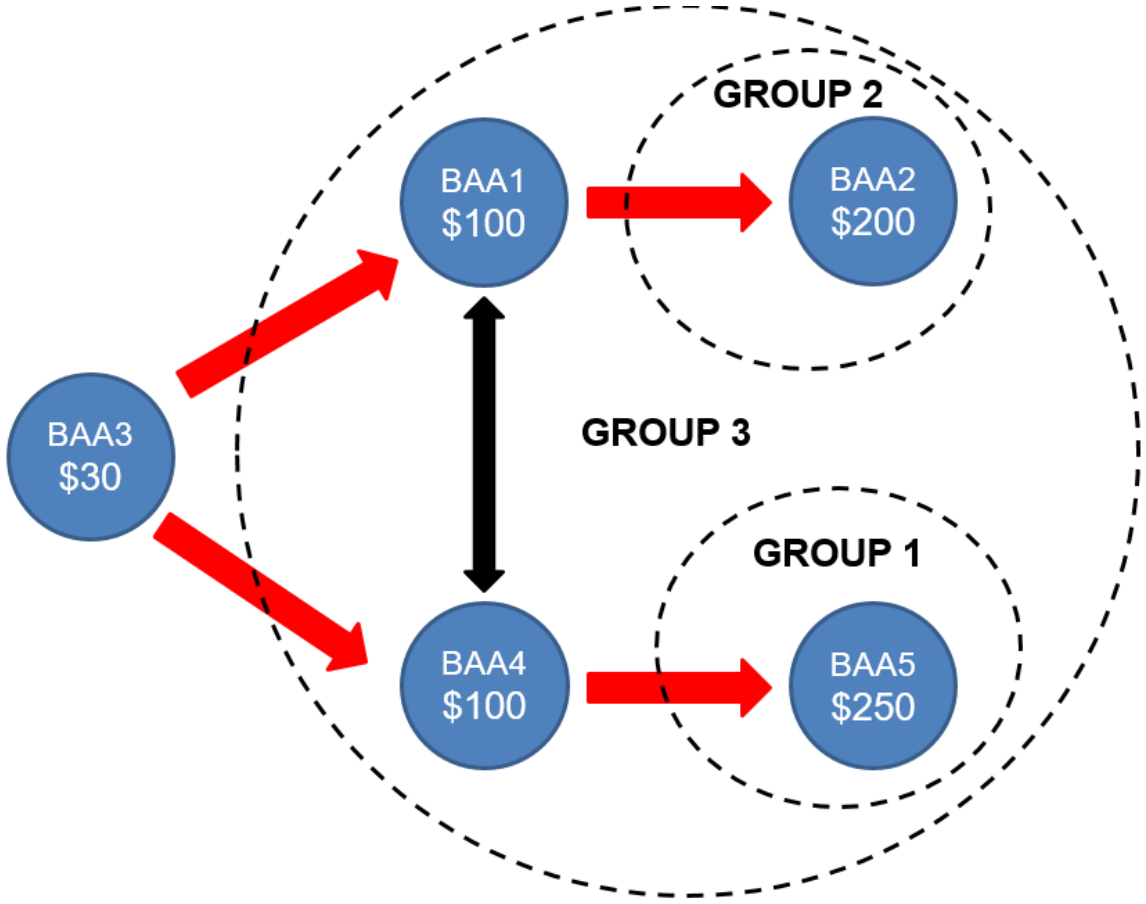


To carry out these tests the ISO would rank all balancing authority areas in descending order of their power balance constraint shadow price, then group balancing authority areas hierarchically from highest price to lowest price. At each level, the ISO would test if the supply in the current balancing authority area group can meet the scheduled load in that balancing authority area group competitively. If the balancing authority area group were not competitive, all resources within that balancing authority area group would be subject to local market power mitigation measures. Then the ISO would expand the balancing authority area grouping to include the next tier of balancing authority area(s), and the process repeats until a competitive balancing authority area group is found or the list of balancing authority areas is exhausted. After these tests are

completed, only resource bids of pivotal suppliers in the uncompetitive balancing authority area groups receive mitigated bids at the default energy bids.[27]

Figure 4 illustrates a more complex example, with five balancing authority areas and three groups. In this example, there is congestion from balancing authority area 3 to balancing authority areas 1 and 4. This creates lower prices in balancing authority area 3 and higher prices in balancing authority areas 1 and 4. There is no congestion between balancing authority areas 1 and 4, so those areas have the same price. There is congestion from balancing authority areas 1 and 4 to balancing authority area 2, and this congestion results in higher prices in balancing authority area 2. Finally, there is congestion from balancing authority areas 1 and 4 to balancing authority area 5, and this congestion results in higher prices in balancing authority area 5.

Figure 4: Complex Market Power Grouping Example



[27] The ISO will only consider supply in excess of scheduled load for scheduling coordinators and affiliates as supply counter flow in the dynamic competitive path assessment for the balancing authority area groups.

The ISO proposes to first arrange the balancing authority areas into groups, then to stack those groups from 'most' constrained to 'least' constrained, then perform the dynamic competitive path assessment on those groups until the competitive group is found. Figure 4 details that only balancing authority area 5 will be included in group 1, balancing authority area 2 is included in group 2 and balancing authority areas 1, 2, 4 and 5 area included in group 3. In this proposal group 1 and group 2 will always be tested, however if either group is found to be competitive with the larger group, group 3 will be considered competitive and will not be subject to the test.

3.5.2 *Neighboring Constraints*

Market power mitigation only considers constraints that are within a balancing authority area where the resource is located when determining competitiveness. However, in reality a resource could both contribute to and relieve congestion in a neighboring balancing authority area. The ISO proposes to enhance market power mitigation logic to allow binding constraints in other balancing authorities to affect dynamic competitive path assessments for all resources considered in the ISO markets.

3.6 Other Price Formation Enhancements

The CAISO will consider additional topics for this initiative based on stakeholder feedback.

4 Next Steps

The ISO requests additional feedback from stakeholders on the issues presented in this paper and the scope the CAISO should prioritize in this initiative.

The CAISO will host a stakeholder call on July 12, 2022 to review the issue paper. The CAISO encourages all stakeholders to submit written comments on the issue paper, including additional issues the CAISO should consider as part of this initiative.

Appendix A: Summary of ISO/RTO Scarcity Pricing

Below are summaries of how other ISO/RTOs employ demand curves to relax reserve constraints and produce stepped price signals during scarcity conditions.

Midcontinent Independent System Operator (MISO):

The MISO utilizes demand curves to relax reserve constraints and ensure the market produces scarcity price signals. The three market-wide demand curves the MISO employs are for operative reserves, the sum of regulating and spinning reserves, and regulating reserves. Each of these demand curves are designed to communicate shortages in capacity, regulating, and spinning reserves and the prices produced from these reflect deficiencies in each product in the entire market. These demand curves and rationale behind their designs are detailed in the Energy and Operating Reserve Markets Business Practices Manual Section 5.2.1.1[28]

The MISO fully co-optimizes energy, regulating reserve and contingency reserve requirements in both their day-ahead and real-time energy markets. This differs from the CAISO's design in which energy and ancillary services are only fully co-optimized in the day-ahead market. In the real-time market, the CAISO only procures additional ancillary services if needed.

ISO-New England (ISO-NE):

ISO-NE relaxes real-time reserve constraints depending on the specific reserve requirement. The following reserve constraint penalty factors (RCPFs) are the prices beyond which ISO-NE's real-time dispatch software will no longer re-dispatch the system to maintain reserve requirements[29]:

Constraint RCPF	($/MWh)
Ten Minute Spinning Reserves	$50
Total Ten Minute Reserves	$1,500
Total Thirty Minute Reserves	$1,000

[28] See pages 172 – 182 for information on MISO's demand curves from the Energy and Operating Reserve Markets Business Practices Manual available at https://cdn.misoenergy.org//BPM%20002%20%20Energy%20and%20Operating%20Reserve%20Markets49546.zip

[29] See Section III.2.7A for information on ISO-NE Calculation of Real-Time Reserve Clearing Prices available at https://www.iso-ne.com/static-assets/documents/2014/12/mr1_sec_1_12.pdf

During 5-minute scarcity conditions in which the Total Ten Minute Reserve or Total Thirty Minute Reserve requirements are deficient, the RCPFs will set the real-time reserve price and serve as an adder to the real-time LMP. Assuming all reserve requirements are deficient, the maximum LMP adder that could be applied would equal:

$2,550/MWh (all RCPFs) + $1,000/MWh (energy offer cap) = $3,500/MWh

Additionally, ISO-NE fully co-optimizes reserve requirements in their real-time market for every interval.

New York ISO (NYISO):

The NYISO relaxes reserve constraints using 15 Operating Reserve Demand Curves based on reserve regions. The following table outlines the various demand curves that apply to both the Day-Ahead Market and Real-Time Market[30]

New York Region	Operating Reserve Demand Curve Type	Demand Curve Amount (MW)	Demand Curve ($)
NYCA	Spinning Reserves	All	$775
NYCA	10-Minute Reserves	All	$750
NYCA	30-Minute Reserves	300	$25
		655	$100
		955	$200
		Remainder	$750
Eastern New York (EAST)	Spinning Reserve	All	$25
	10-Minute Reserves	All	$775
	30-Minute Reserves	All	$25
Southeastern New York (SENY)	Spinning Reserve	All	$25
	10-Minute Reserves	All	$25
	30-Minute Reserves	All	$500
	Spinning Reserve	All	$25

[30] See Section 6.8 for information on NYISO's Operating Reserve Demand Curves available at https://www.nyiso.com/documents/20142/2923301/ancserv.pdf/df83ac75-c616-8c89-c66499dfea06fe2f

New York City (N.Y.C.)	10-Minute Reserves	All	$25
	30-Minute Reserves	All	$25
Long Island (LI)	Spinning Reserve	All	$25
	10-Minute Reserves	All	$25
	30-Minute Reserves	All	$25

The NYISO fully co-optimizes energy, reserve, and regulation requirements in their real-time market.

PJM

PJM utilizes a two-step Operative Reserve Demand Curve (ORDC) to relax reserve constraints in which the first step is set at the Reserve Penalty Factor of $850/MWh and the second is at $300/MWh for 190MW of added reserves[31]. The first step of the Reserve Penalty Factor was designed to prevent the reserve market-clearing price from reflecting the incremental costs of resources needed to meet reserve requirements in the shortage or near-shortage conditions. The second step provides protection against price swings associated with scarcity conditions by signaling to market participants if the market is approaching scarcity/shortage conditions.

PJM fully co-optimizes energy and reserves in their day-ahead and real-time markets. When constraints are relaxed and the ORDC is used, the determined penalty factor is included in the calculation of the energy price. This increases the energy price to reflect scarcity/shortage conditions.

Southwest Power Pool (SPP):

SPP uses three demand curves, Contingency Reserve, Regulation-Up Service, and Regulation-Down Service, to set LMPs and market clearing prices during scarcity conditions on either a Reserve Zone or system-wide basis. The prices determined from these demand curves are calculated based on the MW amounts of shortages per product and are outlined in detail within the Market Protocols for SPP Integrated Marketplace Section 4.1.5.5[32].

[31] See Section 4.2.2.1 for information on PJM's Reserve Demand Curves and Penalty Factors in the Energy & Ancillary Services Market Operations Manual available at https://www.pjm.com/-/media/documents/manuals/m11.ashx?la=en

[32] See Section 4.1.5 for information on SPP's demand curves available at https://spp.org/Documents/61445/Integrated%20Marketplace%20Protocols%2075.zip

SPP fully co-optimizes energy and reserves in their day-ahead and real-time markets.

Appendix B: Summary of ISO/RTO Fast-Start Pricing

RTO/ISO	Key Elements
MISO	- Definition: Start-up time of one hour or less, and minimum run-time of one hour or less; fuel-limited resources excluded - Amortizes commitment costs utilizing economic maximum operating limit as capacity value - Relaxes economic minimum operating limit to zero in the ex post pricing run - Fast-start pricing is both in the Day-Ahead and Real-Time Markets
ISO-NE	- Definition: Start-up time 30 minutes or under; minimum run-time of one hour or less - Minimum output relaxed to zero - Commitment costs amortized over maximum output - No-load cost also added into the offer price throughout the resource's actual run time (beyond minimum run time) - Only applies to committed resources - FSR pricing only included in the Real-Time Market
NYISO	- Definition: Start-up time of 30 minutes or less; minimum run-time of one hour or less - FSR start-up costs and minimum generation costs are an adjustment to the resource incremental energy cost curve in the Day-Ahead Market and Real-Time Market software ideal dispatch - For dispatchable resources, relax minimum generation constraints down to zero - FSR may increase the dollar component of their Minimum Generation Bids and Regulation Service Bids in the Real-Time Market, compared to Day-Ahead Bids, when the Fast-Start Resources received a Day-Ahead schedule.
SPP	- Definition: Start-up time offer of ten minutes or less and a minimum run-time offer of an hour or less - Calculates a composite energy offer for use in the co-optimization of energy and operating reserves by adding the resource's amortized start-up and no-load costs to its energy offer curve - Commitment costs amortized over the resource's economic maximum operating limit and its minimum run time over one hour - Economic Minimum Operating Limit Relaxation: relaxed to zero during pricing run
PJM	- Definition: Start-up time and minimum run-time of an hour or less - Amortizes start-up and no-load costs in "effective" offer using integer relaxation (to provide approximation of the convex-hull relaxation)

	- Implements separate dispatch and pricing runs in Day-Ahead and Real-time Markets (but based on the same optimization case to better align the dispatch and pricing runs)