UNITED STATES OF AMERICA
BEFORE
THE FEDERAL ENERGY REGULATORY COMMISSION

Meeting the Challenge of Resource Adequacy in Regional Transmission Organization and Independent System Operator Regions — Docket No. AD25-7-000

OPENING STATEMENT OF TRAVIS KAVULLA
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I am thankful for the Commission's invitation to speak to this important technical conference, and in these comments, I seek to emphasize a frequently overlooked but important attribute of competitive markets: their ability to encourage capital formation over the long term to create a reliable and affordable supply of goods. Competitive markets do this by giving space for bilateral dealmaking to occur, with this trade representing the differing viewpoints and business models of willing sellers and willing buyers over different tenors and contractual terms to bargain for what otherwise would be regarded as a product uniform in its attributes, price, and duration.

Achieving this result in a market for a product defined by government regulation—electric generating capacity (or simply "capacity" as I will refer to it here)—is challenging, but two lessons in market design may be gleaned from the markets at issue in this panel. First, a relatively prompt "showing" of adequate capacity to meet regulatory requirements, subject to adverse financial outcomes or penalties for any shortfall, all but guarantees that those who bear the purchase obligation will purchase the commodity in advance if they possibly can. Second, certain markets may have a capacity obligation, but lack a centralized auction that provides a clearly defined, singular price; this design necessitates bilateral dealmaking for capacity between buyers and sellers. While this approach avoids the controversies of centralized auction design, it has its own trade-offs and may serve only to conceal the cost of capacity and the reliability it provides, not necessarily make it more affordable.

I. About NRG Energy

NRG Energy Inc. ("NRG") is a consumer-facing, integrated energy company that serves 8 million energy and energy services home and business customers through our retail power and gas and home-services companies. We own and operate approximately 11 GWs of power-generation and, on May 12, 2025, publicly announced a purchase and sale agreement with LS Power to acquire an additional 12.8 GWs of generation along with a 6 GW demand response business, adding to capabilities NRG has developed over decades in both these industries.[1] The largest part of our power-generation and power-sales business to date takes place in markets without a centralized capacity auction, which is the topic of this panel.

II. Introduction

Competitive markets are characterized by the ability of willing buyers and willing sellers to come together in a roughly co-equal relationship to engage in trade to their mutual advantage. This is not necessarily something that characterizes the trade in capacity, which arises from a regulatory obligation to purchase this product in furtherance of systemic resource adequacy needs. The capacity product is not by itself, and as defined within the regulatory paradigm, something that any individual buyer would have need of or would wish to buy.

Customers, of course, want a reliable and affordable supply of *energy*. It is only because of the failure of energy markets on their own to assure a nearly-always-adequate supply that regulators have invented a product another step removed; that is, *capacity*.[2] Across regions, the product has many permutations but, wherever an obligation to buy it exists, it follows that there is some governmental regulator—either this Commission or another—that has put itself in place of consumers to define this peculiar product, something that is adjacent to and merely supportive of the thing that the nation's electricity consumers actually want and need: reliable energy.

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[1] *NRG Energy Inc. to Acquire Premier Power Portfolio from LS Power; Transforming Generation Fleet for Growing Demand*, BUSINESSWIRE, (May 12, 2025, 7:00 AM), https://www.businesswire.com/news/home/20250512012040/en/NRG-Energy-Inc.-to-Acquire-Premier-Power-Portfolio-from-LS-Power-Transforming-Generation-Fleet-for-Growing-Demand.

[2] *See* Paul Joskow, *Capacity payments in imperfect electricity markets: Need and design*, 16 UTILITIES POL'Y 159 (2008); Frank Wolak, *Market Design in an Intermittent Renewable Future*, IEEE POWER AND ENERGY, (Jan/Feb. 2021), https://web.stanford.edu/group/fwolak/cgi-bin/sites/default/files/wolak_ieee_final.pdf.

For the purposes of these comments, I have located the most recent capacity prices to which customers are exposed *if* they or their agents have not otherwise self-arranged or bilaterally contracted for capacity. In other words, these are the *marginal* costs for capacity. In certain markets, the majority of customers will be exposed to these costs, and in others, only a single-digit percentage of total demand will be, because of the *retail* decisions of individual customers or by load-serving entities ("LSE") who serve them, subject to state and local regulation, to otherwise secure supply at a possibly higher or lower cost.

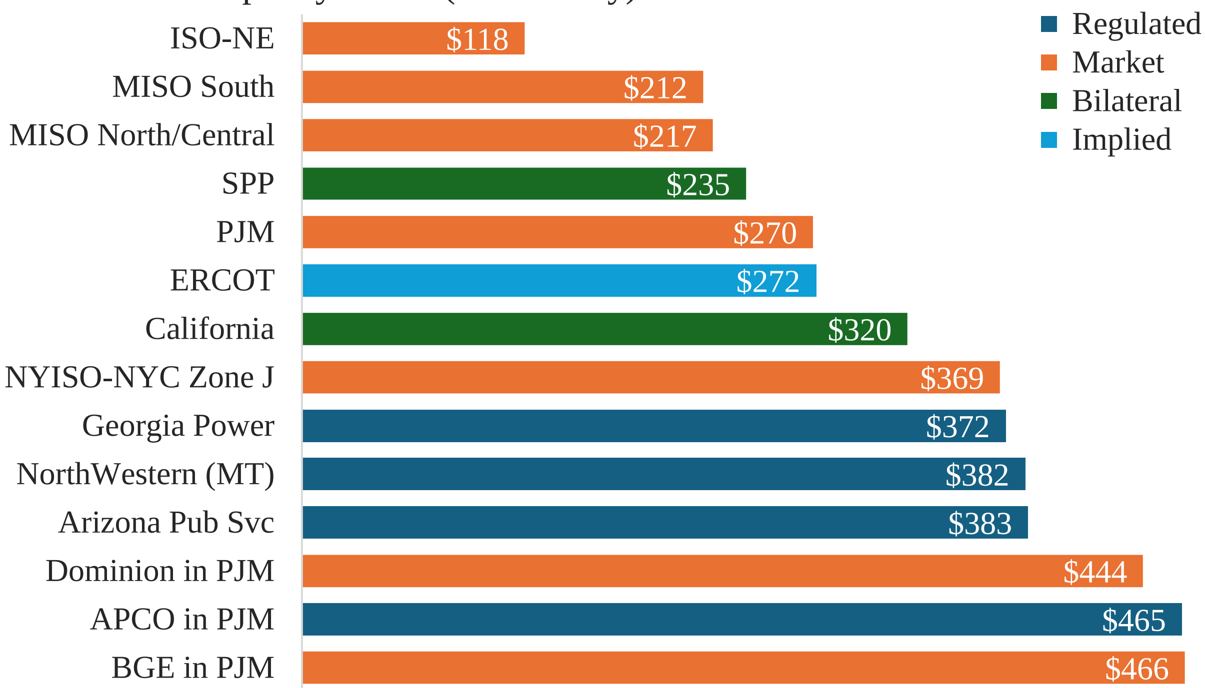
Capacity prices in the table below result from the following pricing and ratemaking mechanisms:

- centralized auctions, in the case of PJM,[3] MISO,[4] NYISO,[5] and ISO-New England[6];
- exclusively bilateral markets, in the case of California's capacity product, called "resource adequacy" or "RA,"[7] and in SPP, which imposes a capacity obligation on all LSEs;[8]
- the state-regulated price of utility capacity, including those that allow some form of retail competition;[9] and

[3] An annual auction resulting in the majority of the Regional Transmission Organization ("RTO") clearing capacity at $269.92 per MW-Day, with BGE and Dominion zones clearing $466.35 and $444.26 per MW-Day, respectively. *2025/2026 Base Residual Auction: Auction Report*, PJM INTERCONNECTION (July 30, 2024), https://www.pjm.com/-/media/DotCom/markets-ops/rpm/rpm-auction-info/2025-2026/2025-2026-base-residual-auction-report.ashx.
[4] A four-seasons auction resulting in $212 to $217 per MW-Day annualized for the North/Central and South regions, respectively. *Planning Resource Auction: Results for Planning Year 2025-26,* MISO (Apr. 2025), https://cdn.misoenergy.org/2025%20PRA%20Results%20Posting%2020250428694160.pdf.
[5] A simple average of the May 2025 auction for summer and Nov 2024 auction for winter 2024-25. Monthly Auction *ISO Monthly Auction Summary*, NYISO, http://icap.nyiso.com/ucap/public/auc_view_monthly_detail.do (last visited May 16, 2025).
[6] An annual auction resulting in $3.58 per kW-month. *New England's Forward Capacity Auction Closes with Adequate Power System Resources for 2027/2028,* ISO-NEW ENGLAND, https://www.iso-ne.com/static-assets/documents/100008/20240209_pr_fca18_initial_results.pdf (last visited May 16, 2025).
[7] Little information is publicly available about Resource Adequacy pricing in California, but the California Public Utilities Commission ("CPUC") publishes a periodic report on RA pricing two years in arrears. System RA priced on average at $9.73 per kW-month for 2024, based on purchase data reported by LSEs subject to the CPUC's jurisdiction. This price does not include Local and Flexible RA. *2022 Resource Adequacy Report,* CPUC, (May 2024) at 26 https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/2022-ra-report_05022024.pdf.
[8] SPP employs the nomenclature "load-responsible entity" ("LRE"), which can be a combination of LSE, for which a single LRE is responsible, but for simplicity, I use LSE throughout these comments. SPP market participants report bilateral pricing converging around a dated Cost of New Entry Value ("CONE") that establishes the baseline of deficiency payments in SPP. *See infra* discussion in Sec. III.B of these comments.
[9] Large customers in the Appalachian Power Company ("APCO") and Arizona Public Service Company ("APS") service territories in Virginia and Arizona have the statutory and tariff right, respectively, to obtain third-party energy

- ERCOT's market design, which expressly avoids a trade in capacity, but where nevertheless an implied value of it can be calculated as a measure of the revenue a typical combustion turbine earns in the energy and ancillary-services markets in excess of the unit's marginal costs.[10]

Table 1
Capacity Prices ($/MW-Day) in Various RTOs and IOUs



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supply but must either pay the incumbent utility a regulated rate for capacity or otherwise self-supply the product. Meanwhile, values for regulated utilities Georgia Power and NorthWestern are based on the latest-calculated avoided-cost payments for capacity those utilities make to "Qualifying Facilities."

APCO's regulated capacity rate is $464.74 per MW-Day. *Schedule 8.1 – Appendix 2: APCO Capacity Compensation Formula Rate, To Be Effective June 1, 2024 to May 31, 2025,* PJM INTERCONNECTION, https://www.pjm.com/-/media/DotCom/markets-ops/settlements/frr-lse-capacity-rates/2024/schedule-8-1-appendix-2.pdf (last visited May 16, 2025).

APS's regulated capacity rate is $11.664 per kW-month, which applies to retail-choice customers as of March 2025 who do not self-supply capacity and is also the unbundled stated rate for APS-supplied customers. Rate Schedule E-34 (Rev'd No. 24), "Extra Large General Service," Arizona Public Service Co., (eff. March 8, 2024).

Georgia Power Company, 2023 IRP Update, "Avoided Cost Projections: 4822 Avoided Cost – Non-Intermittent Qualifying Facilities" (June 7, 2024).

Montana Integrated Resource Plan 2023, NORTHWESTERN ENERGY at 33, https://www.northwesternenergy.com/docs/default-source/default-document-library/about-us/erp-irp/2023_montana_irp_final.pdf (last visited May 16, 2025) (calculating "the cost of procuring capacity").

[10] The sum of peaker net margin in ERCOT calculated as of Dec. 31, 2024. Underlying data available at: https://www.ercot.com/mp/data-products/data-product-details?id=NP4-790-CD.

Despite the pervasive regulation of the *capacity* product, beginning with the act of inventing it and the obligation to purchase it, competitive features can be introduced to the market for capacity sales and purchases. In the eastern restructured markets, Regional Transmission Organizations ("RTO") have established competitive auctions in which generators vie against one another. These capacity auctions result in contracts to supply capacity in a quantity sufficient to meet projected demand at uniform price, subject to locational constraints. However, the extent to which consumers actually are exposed to these prices is a function of the bilateral trading for capacity that insulates capacity buyers' and capacity sellers' exposure versus the auctions' prices.

In California and the SPP states, a capacity obligation exists under state and federal regulation, but rather than an auction, the purchase and sale of capacity happens almost exclusively on the basis of decisions of LSEs and capacity resources on how to and from whom one buys and sells. Sometimes, such as in SPP, these entities are one and the same, especially where vertically integrated utility monopolies exist. Here, one may hope, the utilities run fair competitive solicitations for resources subject to state oversight or appropriate supervision by municipal and co-operative governing bodies, and provide an opportunity for an active demand side to reduce customers' capacity needs despite a single firm's legal right to supply that demand. In California, with a higher degree of retail competition, bilateral dealmaking flourishes, and buyer and sellers usually contract in an arm's-length relationship, but again for not-quite-voluntary reasons. In both the CAISO and SPP footprints, capacity purchases unfold due to a combination of positive state regulatory requirements and the threat of financial penalties under state and federal tariffs.

It is important to note that in either of these models, the end state of capacity market design should not be a market whose singular forward or spot price is what all consumers pay. Indeed, the risk of exposing one's demand to a spot market is something no reasonable firm would do in virtually any industry, if the firm could help it. Businesses like NRG crave a measure of certainty around the cost of goods they sell, and if they cannot obtain it, they will either risk-adjust the price of the product they offer to account for the uncertainty, or leverage contractual terms that shift that risk to their consumers. There are some market designs that will tend to drive more dependency upon an auction's single-point-in-time price, and some that will result in more bilateral contracting to hedge exposure to any given auction result or reserve price.

To take one example, the way in which PJM recently has been regulated tends to expose consumers to its centralized auction's pricing, for at least three reasons. First, numerous regulatory interventions have increased the risk that longer-term bilateral contracts will have the value of the bargain they represent eroded. Counterparties are generally more willing to enter into long-term deals for a commodity if the underlying market structure against which that deal settles is clearly and consistently defined. Additionally, nearly all commercial contracts have change-in-law provisions, PJM and the Commission are constantly changing the rules. Customers therefore find themselves either paying a significant risk premium to pay a fixed, long-term price that encompasses this regulatory uncertainty or, alternatively, for a lower price they may obtain a contract with change-in-law provisions that will be invoked when PJM and the Commission once more change the rules. For these reasons, bilateral contracting has naturally diminished. Ironically, a negative feedback loop is present today in the PJM market. Many of the changes to the PJM market are precipitated by buyers or even sellers who are unhappy with their or their constituents' exposure to a single auction's price outcome. Bilateral contracting could avoid this exposure, but such contracting will be less likely to occur the more frequently the design of the centralized auction is revised. This exposure to a singular auction price in PJM has become a self-perpetuating problem, which will require leadership to resolve.

Second, beyond this morass, the forward nature of the PJM auction creates a timing dynamic where LSEs simply accept exposure to the ultimate spot price because, in a competitive market that features active customer switching between suppliers, the quantity of LSEs' obligations are not contemporaneous with the risk and credit requirements of taking bilateral positions in capacity that will settle only years later. Unless customers themselves wish to enter into retail contracts with similar tenors, the corresponding upstream activity in bilateral capacity contracting could be limited.[11] Prompt auctions like NYISO's avoid this dynamic and in doing so encourage bilateral contracting, but PJM's forward auction does not.

[11] Brian Martucci, *Constellation plans 2028 restart of Three Mile Island unit 1, spurred by Microsoft PPA*, UTILITY DIVE (Sept. 20, 2024), https://www.utilitydive.com/news/constellation-three-mile-island-nuclear-power-plant-microsoft-data-center-ppa/727652/.

Third and finally, restructured states' public utility commissions still make the decision for how capacity should be supplied to those customers who either do not or, because of retail monopolies, cannot shop for alternative providers. A majority of commercial and industrial customers select a third-party provider in the states that permit them to do so; however, 72.5% of total volumes across all customer classes in the PJM market continue to be served by regulated utilities.[12] These states have the opportunity to require the providers of this default service to bear the risk of capacity pricing, but a number of states—including some states who now object to the high prices of the PJM capacity auction—have made the conscious decision to simply pass through that price directly to consumers without requiring any intermediation by suppliers.[13]

In contrast, one may consider approaches that do not force customers into exposure to a market's singular forward or spot price, including the markets at issue in this panel: California and SPP. Here, buyers and sellers are effectively forced into bilateral dealmaking, because there is no centralized market clearing function for capacity. This still is not some kind of free market; the price and quantities of capacity which LSEs will buy are guided by regulatory decisions about the penalty of not doing so to the extent required by regulatory estimates of a reserve margin necessary to safeguard resource adequacy. Nevertheless, bilateral deals are the norm, and they exhibit a wide range of product differentiation, including not only price and term, but ownership models that weigh on capital formation, credit requirements in view of the risks of counterparties, the bundling of energy or other services (such as congestion or basis risk mitigation) together with capacity, and numerous other features. This is how competitive markets *should* work, creating a diverse set of products suited to buyers' preferences and needs, while rising to the regulatory mandate for resource adequacy. In the shorter-term and less-change-prone NYISO spot auction, one also sees a flourishing of bilateral trading occur. Similarly, in MISO,

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NRG expects significant new generation to enter into the PJM market on the strength of longer-term retail contracts with large loads.

[12] For the states that do permit customer choice, the majority of commercial and industrial customers in PJM elect to take service from a third-party competitive retailer, ranging from 85% in Pennsylvania to 56% in Delaware. EIA Form 861-A (2023).

[13] Board of Public Utilities, *In re of the Provision of Basic Generation Service (BGS) for the Period Beginning June 1, 2025,* Decision and Order (Nov. 21, 2024), Docket No. ER24030191, at 8-10.

"more than 90%" of all load is hedged and not exposed to the spot capacity price resulting from the Planning Resource Auction.[14]

It may seem paradoxical that regulation that creates a "prompt" market or an obligation to "show" capacity outside any auction-based clearing mechanism would create *longer-term* assurances of resource adequacy, but they may well do so. Provided that the market construct that establishes the prices against which the contracts settle is stable, buyers and sellers can formulate their view of the fair value of the bilateral contracts, thereby facilitating trade. The risk of exposure to extreme spot prices, or penalties at a high reserve price, motivates longer-term arrangements to hedge this risk of ending up without a seat in a capacity-market version of musical chairs. Or, as traders sometimes jest, it is better to be "long and wrong" than "short and fired." Regulatory designs that promote this trading ethos work to align competitive-market behavior with resource adequacy. Shorter-term capacity markets or obligations can tend to promote arrangements whereby willing buyer–seller pairs come together in trade for the product and, as importantly, energy and other services.

Finally, the obligation to buy *capacity* for resource adequacy is not the whole ball game in the regulatory design of the markets at issue on this panel. California and SPP are suffuse with regulatory requirements that have nothing to do with the capacity function of this Commission's regulation, but which interact with that function and are more fully explained below. Suffice it to say that California is an unusual jurisdiction that, in its own way, has successfully required LSEs in the presence of retail competition to enter into long-term resource procurements, in furtherance of both its resource-adequacy and clean-energy policies. Some of these California policy decisions have a large price tag, and California regulation tends toward needless duplication and complexity. Meanwhile, most SPP demand exists behind the retail monopolies of investor-owned utilities, who have a rate-base incentive to own generation to the exclusion of third parties.[15] This domineering position has inhibited the innovations and capital churn that characterize more competitive markets, and negatively affects the liquidity of trading in the SPP market.

[14] Amanda Durish Cook, *MISO Summer Capacity Prices Shoot to $666.50 in 2025/26 Auction*, RTO INSIDER (Apr. 28, 2025), https://www.rtoinsider.com/104023-miso-summer-capacity-prices-2025-26-auction/.
[15] It should be noted, however, that most LSEs in SPP are municipal or co-operative utilities, though they make up the minority of load.

III. The California Independent System Operator and the Southwest Power Pool

SPP's and CAISO's market designs have taken a relatively novel approach to resource adequacy, where the centralized market functions only as a backstop or a double-check of sorts for capacity obligations that are worked out by each LSE within those markets. There are still mandatory features of capacity planning, but are not combined with an auction in the RTOs' rules.

In the case of SPP, this occurs through integrated resource planning undertaken by the market's 64 entities that currently have load-service obligations, nearly all of which enjoy a monopoly in their particular service territory.[16] The largest of these serve the vast majority of load from capacity resources that they own or control as part of a vertically integrated, bundled business model that sits essentially outside this Commission's regulation. SPP publishes a transparent, detailed report indicating the supply mix of each of these, which also shows the extent to which they are dependent on capacity purchases both within SPP and deliverable to the market's footprint.[17] SPP's Regional State Committee establishes a resource adequacy requirement based on a reserve margin for the market, which then is applied to each LSE. Each LSE met or exceeded its reserve-margin obligations in 2024.[18] In the present circumstances, SPP's capacity function is purely as a backstop—though an influential one, as it guides the LSEs' investment and purchasing decisions for capacity into the future.

In the case of CAISO, the California Energy Commission creates a load forecast that is devolved to each of the 98 LSEs in the market.[19] These LSEs in turn, face an obligation to self-supply or bilaterally procure an adequate amount of the "Resource Adequacy" product from generation or demand-response resources.[20] Despite its smaller size, the footprint of CAISO has

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[16] Or "load responsible entity" in the parlance of SPP, which includes upstream entities responsible for full-requirements obligations to certain LSEs. Two such entities are excluded from this count, because they currently have no load. *2024 SPP Resource Adequacy Report,* SPP at 2 (June 14, 2024).
[17] *Id.*
[18] *Id.,* at 5.
[19] Electric Load-Serving Entities ("LSE") registered with the state of California: (1) California Open Data Portal, California Energy Commission, Electric LSE (IOU & POU), available at: https://data.ca.gov/dataset/electric-load-serving-entities-iou-pou (last visited May 16, 2025); (2) California Open Data Portal, California Energy Commission, Electric LSE Entities (Other), available at: https://data.ca.gov/dataset/electric-load-serving-entities-other (last visited May 16, 2025); (3) California Public Utilities Commission, Registered Electric Service Providers, available at: https://apps.cpuc.ca.gov/apex/f?p=511:1:0::NO (last updated Apr. 7, 2025, 1:33 PM).
[20] Most of these LSEs are jurisdictional to the CPUC for purposes of their Resource Adequacy "showing."

many more LSEs than SPP, and the marketplace is characterized by some degree of retail competition, as many Californians have a choice between two energy suppliers, the incumbent, investor-owned utility and a community choice aggregator. Still other customers, primarily larger commercial and industrial customers, may procure their supply through a wider variety of competitive retailers as part of the state's capped Direct Access program. Other parts of California, mostly outside of CAISO, defy any of these three classifications of LSEs, notably public-power utilities with no retail competition.

A. Further observations on the California Independent System Operator

California is a complex regulatory environment. Responsibilities for resource adequacy in California are divided between a number of agencies, including two state commissions and CAISO. In this scheme, the California Energy Commission is responsible for the state's load forecast that establishes the demand for the state's capacity product, itself called "Resource Adequacy" or "RA."[21] The California Public Utilities Commission ("CPUC") is responsible for regulating most of the states' LSEs and enforcing the mandatory purchase obligation, subject to penalty, of RA, and it is also responsible for accrediting resources for their sales eligibility for RA.[22] Finally, CAISO measures the performance of RA resources, assessing bonuses and any penalties that apply, and on very rare occasions is responsible for backstop procurement of RA, while it also runs its own concurrent assessment of resource adequacy that may or may not align with the state agencies' assessments.[23]

California's capacity product is also unusually complex. The RA product is sold on a monthly basis and, until the beginning of 2025, the quantity of the purchase obligation for an LSE , and the accredited sales potential of any given resource, was defined by the tightest forecast conditions within the relevant month. The CPUC recently reformed its RA scheme to a "slice of day" approach, which divides each month into twenty-four hours to better reflect both the diurnal characteristics and duration limitations of the fastest-growing resources in the state:

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[21] *Demand-Side Modeling*, CALIFORNIA ENERGY COMM'N, https://www.energy.ca.gov/data-reports/california-energy-planning-library/forecasts-and-system-planning/demand-side-modeling (last visited May 16, 2025).
[22] *Resource Adequacy*, CPUC, https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/electric-power-procurement/resource-adequacy-homepage (last visited May 16, 2025).
[23] CAISO, Tariff Section 43A: Capacity procurement mechanism (as of May 1, 2025). https://www.caiso.com/documents/section-43a-capacity-procurement-mechanism-as-of-may-1-2025.pdf.

solar and battery storage.[24] This effectively creates an hourly effective load carrying capability value for resources, and a concomitant measurement of LSEs' demand. LSEs must demonstrate that they have procured sufficient capacity by the end of October each year, covering 90% of their RA obligation for the five summer months of the upcoming compliance year. Additionally, a true-up process occurs 45 days before the compliance month to confirm that 100% of the monthly RA obligation has been met.[25]

Generally, when RA is discussed, the implication is "System RA," but two other obligations facing customers and their LSEs exist, which include "Flexible RA" and "Local RA." Local RA ensures the geographic availability of capacity. CAISO determines Local RA requirements annually to prevent local reliability issues arising from transmission congestion or outages, ensuring that adequate capacity is available within specific geographic areas to maintain grid stability. In 2020, the CPUC established a Central Procurement Entity ("CPE") and a hybrid central procurement framework in PG&E's and SCE's distribution service areas, which subsequently required the CPE to procure Local RA, a function it has performed since 2023.[26] The CPE is responsible for procuring Local RA on behalf of LSEs.[27] Flexible RA, on the other hand, ensures operational readiness to address real-time fluctuations in the grid. The CPUC adopted a flexible RA requirement for LSEs in 2015, where LSEs must demonstrate that they have procured 90% of their monthly flexible capacity requirements in the year-ahead process and 100% of their flexible capacity requirements in the month-ahead process.[28] While System RA drives the largest costs, Local and Flexible RA also impose costs on customers.[29]

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[24] *2025 Resource Adequacy and Slice of Day Guide,* CPUC, (Sept. 25, 2024, *rev'd* March 27, 2025). https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/resource-adequacy-compliance-materials/guides-and-resources/2025-ra-slice-of-day-filing-guide1-32725.pdf.
[25] *Id*. at 18.
[26] *Decision on Integrated Resource Planning and Procurement,* CPUC (D.20-03-028), (June 17, 2020), https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M340/K671/340671902.PDF.
[27] For its three-year forward obligation, each LSE in the SDG&E service area must demonstrate procurement of 100% of Local RA obligation for each month of compliance years one and two and 50% of Local RA obligation for year three.
[28] *2022 Resource Adequacy Report,* CPUC (2024), https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/resource-adequacy-homepage/2022-ra-report_05022024.pdf.
[29] The weighted average System RA price was $7.67/kW-month, representing 99,685 MWs of contracted capacity. The weighted average Local RA price was $7.62/kW-month, representing 36,387 MWs of contracted capacity. The weighted average Flexible RA price was $6.61/kW-month, representing 12,503 MWs of contracted capacity. *Id.*

1. *The Trade in California's 'Resource Adequacy' Product*

While complex, the System RA product is widely traded, usually liquid, and a brokerage industry exists to facilitate bids and offers across the wide array of market participants that exist in this space. NRG has been able to purchase RA in ways that meet the particular requests and needs of our customers, who typically have a choice between us and other Direct Access providers, the incumbent utility, and a community choice aggregator. The rollout of the slice-of-day reform has added more complexity to the market, but so far has proceeded smoothly, and without increasing prices or diminishing liquidity in the market. Indeed, based on NRG's market information, prices have declined since the tight market conditions of previous years as batteries have been added to the market. The RA construct has adapted in view of California and the West's changing resource mix, but it has not proven singularly effective as a device to ensure resource adequacy, as described below.

Under its Commission-approved tariff, CAISO has the authority to engage in backstop procurements for resource-adequacy purposes, the costs of which are borne by the deficient LSE or uplifted to all market participants should no deficiency on the part of any individual LSE be observed, a condition which may obtain if the CAISO's backstop forecast does not align with the state government's projections and LSE-facing requirements. It also administers a performance-based rule to measure the performance of RA resources based on their availability, Resource Adequacy Availability Incentive Mechanism ("RAAIM"), though this is undergoing a reform and being turned into a new mechanism, Measuring Unavailable RA ("MURA"), which would assess unavailability during stressed grid conditions and allocate the penalty costs collected from underperforming RA to load. MURA is currently undergoing a CAISO stakeholder process to address availability, assessment period, price of penalty, and cost allocation of penalties collected.[30] The CAISO's backstop procurement authority is very seldom relied upon. However, it is notable that CAISO has used system resource adequacy concerns as a trigger for subjecting power resources in its footprint to its "reliability must run" ("RMR") tariff at cost-based rates.[31] This marked the first time in recent history that federal authorities were used for system resource

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[30] *Resource Adequacy Modeling and Program Design*, CAISO (Feb. 11, 2025), https://stakeholdercenter.caiso.com/InitiativeDocuments/Presentation-Resource-Adequacy-Modeling-and-Program-Design-Feb-11-2025.pdf.

[31] Hudson Sangree, *FERC OKs CAISO RMR agreement for 27.5-MW plant*, RTO INSIDER (Apr. 18, 2021) https://www.rtoinsider.com/20120-ferc-oks-caiso-rmr-agreement-for-27-5-mw-plant/.

adequacy purposes, which despite the obvious differences in California's political inclinations, foreshadowed a similar nationwide approach taken by a recent presidential executive order.[32]

After the invocation of CAISO's RMR tariff for state resource adequacy purposes, the state government took further steps in this domain by establishing a state-backed strategic reserve. This reserve consists of older natural-gas-fired steam plants (totaling 3,079 MWs in 2025), and, as during the California Electricity Crisis, the purchases were made by the California Department of Water Resources, effectively socializing the costs of the out-of-market intervention to all California taxpayers.[33]

There is no price cap for RA in California.[34] When supply–demand conditions are tight, and in the presence of state-backed counterparties willing to pay nearly any price for capacity, there is a risk that economic withholding can occur. At its highest price, NRG's trading team observed quotes of $110 per kW-month for the System RA product for summer 2025—the equivalent of more than $3,500 per MW-Day, more than 10x the recent PJM clearing price.[35]

In a context of scarcity, a residual auction's clearing function would tend to produce greater transparency and a clearer answer to the question of whether sufficient supply of the RA product was, in fact, available in the market. Yet, capacity auctions in California are considered largely synonymous with federal regulatory overhang, which has been anathema to the region since the California Electricity Crisis at the beginning of this century. Among other optional features of RTO market design, California and other Western policymakers have thus avoided a Commission-regulated capacity auction, but in doing so, they have exposed themselves to greater opportunities for the exercise of market power—an irony, given the causes of the calamity that produced this political posture.

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[32] President Donald J. Trump, "Strengthening the Reliability and Security of the United States Electric Grid" (Apr. 8, 2025). https://www.whitehouse.gov/presidential-actions/2025/04/strengthening-the-reliability-and-security-of-the-united-states-electric-grid/.

[33] *Electricity Supply Strategic Reliability Reserve Program update,* CALIFORNIA DEPARTMENT OF WATER RESOURCES (Jan. 1 ,2025), https://www.energy.ca.gov/filebrowser/download/6933?fid=6933.

[34] Notably the Commission tariff imposes a $7.34 per kW-month soft offer cap on the backstop procurement of capacity, but trading for RA bilaterally pursuant to the state regulatory obligations often exceeds this value.

[35] Again, System RA trades as a monthly product so, annualized, the figure would be lower, but still many times the capacity price of any other RTO.

2. State Policy Requirements for Longer-term Investments in Resources

California also has instituted regulatory requirements that are adjacent to the RA purchase obligation to ensure that LSEs not only are making purchases of monthly RA products in furtherance of annual compliance requirements, but also making longer-term investments.

In this regard, the CPUC imposes a requirement for each of its jurisdictional LSEs to file an integrated resource plan ("IRP"). An IRP is a familiar requirement for vertically integrated retail monopolies that plan generation and transmission expansion to serve a captive base of customers, but in California it applies to *all* retail-facing entities under the CPUC's supervision, including fully competitive retailers like NRG who have no captive customer base whatsoever.[36] Part of the IRP regulatory requirements is a "mid-term reliability" ("MTR") procurement obligation. Through the MTR, the CPUC devolves to its jurisdictional LSE a requirement to produce new investment in 12,325 MWs of clean-energy resources signed under contract between June 1, 2023, and June 1, 2026.[37] This has led NRG to sign long-term contracts for solar and storage, supporting long-term positions in those models, although NRG itself has a fluctuating customer base. This attrition risk is dealt with in the competitive market either by liquidating the length of specific contracts or securing new load through the Direct Access lottery system run by PG&E, SCE and SDG&E in an effort to balance and optimize our portfolio.

In other states with such resource-specific requirements, states either have had to rely upon incumbent, un-restructured vertically integrated monopolies or, alternatively, walk back restructuring and convert resource-specific contracts (offshore wind in certain eastern states, for example) into nonbypassable surcharges that flow through the transmission-and-distribution utility's portion of the customer bill. These eastern states have thus created a situation where costs for generation, a competitive market, are infiltrating the regulated costs of utilities.

Yet in California, the state has leveraged its restructured and partially competitive retail market to support these longer-term investments. Contracts for those investments are being consummated between LSEs and new renewable and storage projects, and those investments'

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[36] *Integrated Resource Planning*, CPUC, https://www.cpuc.ca.gov/irp/ (last visited May 16, 2025).
[37] *Summary of Compliance with Integrated Resource Planning (IRP)*, CPUC, Order D.19-11.016 and Mid Term Reliability (MTR) D.21-06-035 Procurement: August 2023 Data Filings" at 4 (Aug. 1, 2023), https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/integrated-resource-plan-and-long-term-procurement-plan-irp-ltpp/publicirpcompliancereport080123.pdf.

commercial operations are being achieved. Between 2021 and 2028, the CPUC directed the procurement of 18,800 MW of new capacity, primarily consisting of battery storage. To put this into context, the California Energy Commission's 1-in-2 peak load forecast for 2025 estimates a demand of 46,094 MW in September (hour ending 18).[38] This mandated procurement accounts for approximately 40% of the projected 2025 peak load. This is a unique development and suggests a captive customer base may not be needed to support a generation-investment scheme that is guided by state policy inclinations. While I believe that the MTR's parameters are too technologically prescriptive, it does seem to be working to achieve the state's declared policy goals in a way that is less disruptive than in the approach certain eastern states have taken.

Table 2

CPUC IRP and MTR Procurement Orders (in MWs Net Qualifying Capacity)[39]

CPUC Orders	Total	2021	2022	2023	2024	2025	2026	2027	2028
D.19-11-016 Applies to 25 LSEs since 18/43 LSEs opted out.	**3,300 MW**	1,650 MW by Aug 1	825 MW by Aug 1	825 MW by Aug 1	n/a	n/a	n/a	n/a	n/a
D.21-06-035 (MTR) Applies to all CPUC-jurisdictional LSEs. No opt-outs allowed.	**11,500 MW**	n/a	n/a	2,000 MW by Aug 1	6,000 MW by June 1	1,500 MW by June 1	n/a[2]	n/a	2,000 MW by June 1
D.23-02-040 (Supplemental MTR) Applies to all CPUC-jurisdictional LSEs. No opt-outs allowed.	**4,000 MW**	n/a	n/a	n/a	n/a	n/a	2,000 MW by June 1	2,000 MW by June 1	n/a
Cumulative Procurement Ordered	**18,800 MW**	1,650 MW	2,475 MW	5,300 MW	11,300 MW	12,800 MW	14,800 MW	16,800 MW	18,800 MW

The Commission has adopted corresponding regulatory reforms whereby CAISO's interconnection process has been geared to help shepherd these states policies. Like other markets, CAISO's generator interconnection queue has suffered extreme backlogs. The CAISO's Cluster 15 study process, which evaluates projects seeking to connect to the CAISO system by 2028, includes 541 new interconnection proposals representing 354,000 megawatts of generation and storage capacity—several times the market's all-time peak demand.[40] In this situation, there are no retail customer relationships for the vast majority of generation projects seeking

[38] *2025 Summer Loads and Resources Assessment*, CAISO (May 5, 2025), https://www.caiso.com/documents/2025-summer-loads-and-resources-assessment.pdf.
[39] *Id*. at 32.
[40] Neil Millar, Vice President, Infrastructure and Operations Planning, Presentation to CEC IEPR Commissioner Workshop on Clean Energy Interconnection – Bulk Grid (May 4, 2023) (available at: https://efiling.energy.ca.gov/GetDocument.aspx?tn=249991&DocumentContentId=84722).

interconnection in CAISO.[41] In view of this obvious mismatch, CAISO took action to create a lasting structural reform to its large generator interconnection procedures, distinct from the one-time emergency procedures that PJM, MISO, and SPP have undertaken.

Under the new CAISO interconnection approach, when there is not enough transmission capacity to accommodate all interconnection requests in a specific delivery zone, CAISO will use a weighted scoring system to allocate priority rights. The scoring system allocates "commercial interest points" to LSEs—on behalf of their customers, and aligned with the fulfillment of the IRP MTR requirements—and those LSEs may vote their points toward one or more of the resources in the queue to grant it a higher-priority status.[42] LSE will naturally tend to vote their points toward projects that are under some form of contractual or other arrangement. Anecdotally, certain power purchase agreement terms improved to the buyer's advantage in exchange for the provision of points to the generator which eliminated interconnection and commercial-operation-date uncertainty that would otherwise raise the price of the Power Purchase Agreement.

3. The Role of Demand-Side Resources

CAISO has struggled to integrate demand response into its market, and the state policy landscape on this point is highly balkanized into various programs, lacking any unifying approach. A previous high point of demand response through utility programs had been facilitated through the presence of back-up generators at large customers' premises, but these diesel-generators were outlawed in the past decade, and demand response has never regained either the quantity or dependability of its performance in the succeeding years. In my view, the overlapping state programs, with CAISO having no particular visibility or defining role in the

[41] This mismatch is a problem that exists throughout Commission-jurisdictional entities on the question of generator interconnection, a sort of "gold rush" for grid access that the Commission's large generator interconnection rules have set loose over the last two decades. It is the subject of a forthcoming paper that the Hon. Eric Blank, Chairman of the Colorado Public Utilities Commission, has graciously allowed me to co-author with him. Blank and Kavulla, *First-in-Time, First-in-Right Generator Interconnect Approaches Limit Access and Raise Costs Under Scarcity Conditions: Toward a Better, Customer-Centric Approach*, (working title, forthcoming) (on file with author).
[42] CAISO divided the overall project scoring into three main categories: 30% for commercial interest points, 35% for project viability, and 35% system need, the latter two being determined by CAISO.

market, is one of the contributory causes to demand response's perceived record of poor performance.[43]

Demand-side participation now depends upon the substantial investments that Californians have made in clean distributed energy resources. Seventeen gigawatts of distributed solar exist behind the meter in California, and with reforms to net energy metering, the state has conveyed a strong incentive that all future behind-the-meter solar should be paired with storage. This has created 2-3 GW of behind-the-meter battery storage capacity, much of which is not "in market" within CAISO market, though it does respond to retail price signals. It would be useful to have this amount of capacity either predictively built into the short- and long-term CAISO load forecast or incentivized to be available to CAISO for dispatch to the extent possible.

Moreso than any other market California is in a situation where distributed resources are having clear and direct effects on the Commission-jurisdictional wholesale market. There are many hours when utility-scale solar resources that participate in the CAISO wholesale market are curtailed due to the production of distribution-side solar resources, for example. It would be beneficial, even necessary, for these two markets to somehow be better integrated or at least visible to one another.

B. Further observations on the Southwest Power Pool

In contrast to CAISO, SPP has a very limited landscape of retail restructuring, with 66 so-called load-responsible entities (which for the sake of consistency I may refer to as "LSEs"), nearly all of which possess a monopoly for customers within their service territory.[44] It is no surprise, then, that to the degree that questions of the purchase and sale of capacity arise, it is often the same entity on either side of the deal in the form of a vertically integrated utility. However, there are many occasions when that is not the case, and then bilateral trading persists both between these vertically integrated monopolies, and also between them and independent power producers.

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[43] *Demand Response Issues and Performance 2024*, CAISO DEPARTMENT OF MARKET MONITORING (Mar. 14, 2025), https://www.caiso.com/documents/demand-response-issues-and-performance-2024-mar-14-2025.pdf.
[44] Only one of these LSEs appears to be a competitive retail LSE. *2024 SPP Resource Adequacy Report,* SPP (June 14, 2024).

SPP imposes a capacity purchase obligation for each of its LSEs. An LSE must turn in a workbook to the RTO by February 1 of each calendar year that shows that it owns or has contracted for adequate capacity to cover its RTO-established needs, including a mandatory reserve margin. A short cure period follows this deadline should an LSE be deficient, a time in which capacity positions of those long and short can also be liquidating in bilateral trading. Should an LSE ultimately be deficient its obligations for capacity, the LSE would be subject to a deficiency payment that orients at a tariff-established value of Cost of New Entry ("CONE") last updated in 2018, which is $85.61 per kW-year, or $234.55 per MW-Day.[45] Depending on the degree to which the entire market faces tight conditions, this penalty ratchets up to a maximum of twice this CONE value.[46]

Like in other markets, a confluence of factors has driven SPP, a place previously flush with excess capacity, to become a much less robustly supplied market. On one hand, the market has seen a withdrawal of supply due to a wave of retirements by coal and older natural-gas units.[47] It also is poised to see diminished supply due to new approaches to accreditation practices that haircut both the value attributed to historically underperforming fossil power plants and the marginal value of renewable resources to reliably serve load in tight conditions.[48] Finally, at the same time as supply has diminished, demand has increased in the form of a higher reserve margin and the institution of a new winter reserve margin mandated by the body of state regulators, the Regional State Committee, that governs the market's resource-adequacy requirements pursuant to this Commission's tariff.[49] Capacity, it must again be observed, is a creation of regulation and, in SPP as elsewhere, it is not just organic resource retirements and load growth, but new regulatory perspectives on the meaning of the capacity product that have caused the supply–demand balance for it to tighten. As a result, prices have risen and SPP expects to be systemically short of capacity in 2027.[50]

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[45] *Open Access Transmission Tariff,* SPP, (6th Rev'd, Vol 1., Attachment AA "Resource Adequacy"), Sec. 13.0 "Cost of New Entry" at 29, https://spp.org/documents/58597/attachment%20aa%20tariff.pdf (last visited May 16, 2025).
[46] *Id.* Sec. 14.2 "Deficiency Payment" at 31.
[47] *See generally*, *Our Generational Challenge: A Reliable Future for Electricity,* SPP (Summer 2024), https://spp.org/media/2163/our-generational-challenge-paper.pdf.
[48] *Resource Adequacy*, SPP, https://www.spp.org/engineering/resource-adequacy/ (last visited May 16, 2025).
[49] *SPP Board approves new planning reserve margins to protect against high winter, summer use*, SPP (Aug. 6, 2024), https://www.spp.org/news-list/spp-board-approves-new-planning-reserve-margins-to-protect-against-high-winter-summer-use/.
[50] *2024 SPP Resource Adequacy Report,* SPP at 4 (June 14, 2024).

The price of capacity in SPP is even less transparent than it is in California, with no public information made available by either the RTO or state regulatory institutions that clearly reports price outcomes of the product's trade on a market-wide basis. However, in conversations with market participants in preparation for this technical conference, the consistent theme was that prices for capacity sales had risen in recent years from approximately $6 per kW-month for the historically tight summer months, with other months only lightly trading, to a price closely approximating the annualized CONE.[51] In other words, the price of capacity purchases in SPP is approaching the cost of the deficiency payment that would otherwise have to be made.

Additionally, because of accreditation changes and the intersection of the annual showing's timing, trading in SPP has taken on the airs of a game of musical chairs. Because February 1 is the date on which the capacity value of resources is calculated for the coming year, poor performance in the preceding months could negatively affect the quantity of capacity a large fossil plant would be eligible to sell; a unit owner who has its own LSE purchase obligation likely will hold that unit until close to or after the showing period so as not to end up short due to the risk of performance, even if that owner otherwise would be long. But after February 1, any given unit's capacity value for the coming compliance year is locked in, with the coming year's performance risk effectively socialized to the market, and LSEs have a short cure period to remedy any short positions. Thus does any length became available for liquidation in the market. This dynamic has also driven capacity trading to shorter tenors.[52]

Since the value of capacity is now trading at levels approaching CONE, it is reasonable to ask whether SPP's representation of a seven-year-old CONE value in the tariff is a reasonable approximation of the actual cost of new entry of a capacity resource. It would be hard to conclude that it is, given the price increases one sees in the market for new dispatchable generation resources. Consequently, the market's penalty structure likely conveys a perverse incentive not to build necessary capacity resources, offset by the reality that many LSEs in this market face a rival perverse incentive to commit as much capital into generation rate base as possible to maximize the profits available to them in cost-of-service regulation administered by State Commissions. Ultimately, given the predominance of state and local regulators' decisions

[51] Author's conversations conducted in May 2025.
[52] *Id.*

as the principal vehicle for LSE cost recovery in the SPP market, long-term resource adequacy considerations are likely to be met by state regulatory designs around the acquisition of new resources by these regulated LSEs. Here, one may hope, that state regulators and other entities responsible for oversight of procurement practices will require and enforce robust, fair, and open solicitations for new capacity resources—but this is classically a role for those state and local regulators and not this Commission.

Finally, there is a significant but unfulfilled role for demand response in the SPP market, the only RTO which does not have an effective means to integrate it into the purchase and sale of the capacity product through wholesale trading. Demand response in SPP historically has been exclusively configured as a reduction to load endogenous to the utility service territory in which the capability is located. However, given the systemic approach to resource adequacy that has been created in the SPP market, where a bilateral trade in a fungible capacity product occurs, it is worth taking measures to integrate demand response aggregations into this trade. Doing so, especially now when conditions are tight but before new supply becomes available, should be pursued with a greater sense of urgency in SPP. The limits on demand response have led to an outcome where individual utility programs collar growth in that market, resulting in the resource amounting to the equivalent of only 1.8% of the total available capacity in SPP, underperforming the resource's presence in the PJM (4.4%) and MISO (6.5%) markets.[53] Demand response is expected to grow in its current configuration in SPP, but the market's stakeholder process has had false starts and a slow process to achieve market rules and assurances around demand-response accreditation and availability that elsewhere have become commonplace. The market's work on this topic began in early 2023 and will not be concluded and implemented until late 2026 at the earliest.

IV. Conclusion

Alternative market design is not a panacea for customer affordability and reliability in a power system that now finds itself supply constrained in the face of unprecedented demand

[53] *2024 SPP Resource Adequacy Report,* SPP at 4 (June 14, 2024). *Compare* with *2025/2026 Base Residual Auction Report*, PJM INTERCONNECTION at 12 (July 30, 2024) and at *Planning Resource Auction: Results for Planning Year 2025-26*, MISO at 41 (Apr 2025) (for demand response available during the peak season of summer).

growth and an awakening to frailties in the system of energy supply that have only lately been appreciated. Throughout the United States, we are witnessing elevated capacity prices on the margin, in situations where customers or their LSEs have not previously arranged for capacity, as can be seen in the analysis presented in Table 1 of these comments.

These higher prices represent the fundamental dynamics of necessary investments in resource adequacy, but they can be mitigated by a few approaches, including a more active demand side as well as approaches to capacity market design that incentivize those who face a capacity purchase obligation to enter into bilateral trading arrangements that may serve to soften the blow of certain volatile market designs that can expose customer demand to high, if perhaps transient, prices. Certain jurisdictions, even in the context of retail restructuring, have also decided to require and not just encourage long-term contracting for capacity. In the best of all worlds, a government obligation for adequate supply would exist for customers who expect and have paid for uninterrupted service, but be fulfilled through a more liberalized trade characterized by deals undertaken by willing buyers and sellers.

There are trade-offs to everything, including with these bilateral markets. It is an open question whether markets that have capacity obligations, but not a centralized clearing function, operate efficiently in situations of rising scarcity. Liquidity and price discovery are concerns in this context, especially in a place like California, which has no price cap for its resource adequacy product. Or, as we see in SPP, certain LSEs may be less likely to re-market capacity to which they have rights in the instance that they may be caught short and penalized. Or certain LSEs with divergent business models may end up with undue advantages—backstop entities, for example, hoovering up available capacity in California due to their governmental backing, to the disadvantage of merchant LSEs. Finally, other nascent capacity-obligation designs, such as the Western Resource Adequacy Program, were overdue in their implementation and are now struggling to get off the ground because, in a world that already faces a capacity shortfall, it is not politically feasible to start a market whose only function is to assess penalties upon those actors who are short.[54]

[signature page follows]

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[54] Dan Catchpole, *Western Power Pool OKs Delaying Binding Launch of the Western Resource Adequacy Program to 2027,* NEWS DATA (Sep. 27, 2024), https://www.newsdata.com/california_energy_markets/regional_roundup/western-power-pool-oks-delaying-binding-launch-of-the-western-resource-adequacy-program-to-2027/article_132d38a4-7d06-11ef-9005-ab74c21562cf.html

Respectfully submitted,

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May 16, 2025