UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

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

Responsive Comments by Ms. Danielle Powers and Mr. Mark Karl of Concentric Energy Advisors

I. INTRODUCTION

We would like to thank the Commission for scheduling the Commissioner-led technical conference to discuss generic issues related to resource adequacy constructs. In particular, we appreciate the focus on the role of capacity markets in Regional Transmission Organization (RTO)/Independent System Operator (ISO) regions that use them, as well as the consideration of alternative constructs in regions without capacity markets.

This is an important and time-sensitive discussion, given the rapidly evolving resource mix, growing reliability concerns, and pressing need for investment signals that align with system needs.

Both Ms. Powers and Mr. Karl have extensive electricity industry experience in both regulated cost-of-service and deregulated wholesale market environments, and both have extensive experience with the design, development, and implementation of ISO/RTO capacity markets. Ms. Powers is an engineer and is the Chief Executive Officer of Concentric Energy Advisors in Marlborough, Massachusetts. She has over thirty-five years of direct experience in the public utility industry, working at an investor-owned utility, an ISO, and most recently as a consultant. She has managed and/or participated in a wide variety of consulting engagements as an expert in wholesale market design, power system operations, and resource planning.

Mr. Karl is an engineer and Executive Advisor at Concentric and has over four decades of energy industry experience, with a tenured history of operations in the wholesale electric market from design to implementation, including resource adequacy. Before joining Concentric, he spent over 23 years at ISO New England, most recently serving as the Vice President of Market Development and Settlements. In that role, he held executive-level responsibility for the design, development, and implementation of all changes to the wholesale electricity markets operated by ISO New England, overseeing the entire

process from inception to implementation, including the stakeholder and regulatory processes as well as market settlements. He previously held leadership positions in Resource Adequacy, Market Development and Integration, and Market Design. Prior to ISO New England, he spent nearly 18 years at an investor-owned utility with positions in generation engineering and operations, system planning, project development, regulatory and economic analysis, and finance.

Mr. Karl and Ms. Powers played a central role in the LICAP litigation and FERC Administrative Law Judge (ALJ)-led settlement process between 2004 and 2006 that resulted in the agreement to implement the Forward Capacity Market in New England. Both were also deeply involved in the development of the market rules, business processes, and systems to implement that market. In addition, both have worked directly with the other U.S. and Canadian ISOs/ RTOs, their market participants, and State/Provincial regulators in a variety of projects related to capacity and resource adequacy.

The purpose of these comments is to provide additional feedback to the Commission and to the industry generally based on the information discussed at the technical conference, along with our broader observations based on recent industry developments. In summary, we suggest that the capacity 'product' in RTOs and ISOs with capacity markets is no longer effective and may be insufficient to ensure continued resource adequacy and system reliability. While the various proposed changes to the capacity product and market offer improvements in assessing adequacy and fuel security, they fall short of addressing the structural barriers to investment and fail to account for the full range of reliability attributes required to operate the power system.

II. CONFERENCE SUMMARY/ OBSERVATIONS

Conference Panel 1 included the ISO/RTO and North American Electric Reliability Corporation (NERC) Chief Executive Officers (CEOs) and a discussion of the current situation in each RTO region, and the nation generally. For the most part, this discussion revealed general agreement. All regions are concerned about accelerating load growth, the decline in firm and dispatchable supply capability, lags in transmission interconnection processes, natural gas risk, and other uncertainties. Most regions are moving ahead with changes to capacity accreditation, even regions without formal capacity markets, and all are focused on interconnection queue improvements, interregional coordination, and addressing winter (fuel) risks. Furthermore, all agree that resource adequacy frameworks must evolve rapidly to address the reliability risks associated with the shifting energy landscape.

Each of the CEOs stated that their regions are currently reliable although each seemed to suggest that efforts underway in each region are expected to address future reliability concerns. Subsequent panels did not uniformly share this assertion, and there was some debate as to how soon increased demand may outstrip operating supply. There also appeared to be some uncertainty about whether the expected or hoped-for replacement capacity will possess the necessary reliability attributes to support system operations.

The Southwest Power Pool (SPP) reported a loss of 7 GW of dispatchable capacity since 2016, while PJM reported a net loss of 5.7 GW since 2015, with multiple nameplate megawatts of renewable resources needed to replace one megawatt of thermal generation. The Midcontinent ISO (MISO) predicts a drop of 32 GW in accredited capacity by 2042, and ISO New England (ISO-NE) is concerned that 4-5 GW of oil/ gas capacity is at risk.

These anticipated reductions in supply must be considered in relation to anticipated load growth:

- SPP forecasts up to a 75% increase in peak demand over 10 years driven by Artificial Intelligence (AI) data centers and electrification.
- PJM is experiencing sharp AI/data center load increases and forecasting difficulty.
- NYISO forecasts load rising from electrification and industrial development with 4.4 GW of large loads in its interconnection queue.
- The California ISO projects 45% peak demand growth forecast over 15 years, with major data center loads increasing after 2028.
- MISO projects a tripling in its compound annual growth rate with AI/data centers and manufacturing resurgence as primary drivers.
- ISO-NE projects 11% consumption growth with winter peaks to rise 30% by 2034.
- NERC notes that nationwide acceleration in load growth is disrupting resource plans, especially due to AI and electrification.

In considering the data presented in this first panel, it is difficult to reconcile the optimism of the RTO CEOs with the data they present. Clearly generation retirements are outstripping resource additions, and the resources entering the system do not offer the same reliability attributes as were provided by retiring resources. While resource interconnection queues remain a key focus for all RTOs, the more pressing concern is not just the pace at which new resources can be added to the system, but that the majority of projects currently in the queues lack the attributes necessary to support system reliability. Furthermore, the build out of additional infrastructure needed to add more remotely-located generation to the system will be lengthy. Even under the best-case

scenario, it is increasingly evident that projected load growth is poised to outpace the capacity of current market structures and RTO business processes—unless meaningful changes are made. Expanding the review of the conference to consider the information provided by the other seven panels reveals a mix of optimism and concern similar to the CEO panel, with some areas of broad agreement. Generally, there was consensus that reforms to resource adequacy cannot wait, and that many resource adequacy mechanisms are not sufficiently aligned with system conditions today or in the immediate future. There was concern that dispatchable thermal and nuclear retirements pose significant risks if not matched with equivalent firm capacity, that the system may face reliability failures before resource adequacy reforms are implemented, and that overreliance on gas-fired resources without fuel assurance can introduce systemic winter risk (e.g., as seen in Winter Storm Uri).

Broad agreement exists on the need to model extreme weather and correlated risks more explicitly in resource adequacy planning and procurement, with widespread acknowledgment that hybrid resources such as solar+storage need new modeling and operational frameworks to be accurately valued and integrated. Concern was expressed that improperly valuing variable and hybrid resources could lead to overestimations of system adequacy, and that recognizing and compensating capabilities like ramping, start-time, duration, and availability during critical hours could provide better investment signals.

The panel discussions did reveal significant areas of disagreement. Stakeholders in ISO/RTOs like PJM and NYISO are split on whether centralized capacity markets ensure long-term reliability or create inefficiencies and price suppression. The California slice-of-day model received both praise and critique. Some view it as an innovative solution to align capacity with net load peaks while others see it as overly complex and region-specific. Some participants argued for retaining or expanding gas as a reliability backstop, while others urged transitioning away as quickly as possible, favoring clean firm resources instead. Finally, disputes emerged over whether FERC or states should lead resource adequacy reform, particularly in regions without formal capacity markets. In short, while there was general agreement that problems exist with the various resource adequacy approaches, there was no consensus on what solutions might be effective.

III. CONTINUED COMMITMENT TO THE CAPACITY PRODUCT IS INADEQUATE TO ENSURE RELIABILITY

Fundamentally, the underlying assumptions of the original capacity construct no longer hold. When capacity markets were first developed, they were built on a foundation

shaped by vertically integrated utilities operating relatively homogenous generation fleets. These fleets were deliberately designed to function as cohesive systems, with resource portfolios optimized to deliver a full suite of reliability attributes—firm fuel supply, dispatchability, voltage support, inertia, and synchronized operation. Capacity was treated as a proxy for the commitment of physical assets that could be counted on to serve peak load, and the system was structured to ensure those assets were not overcommitted.

This framework worked because nearly all resources brought the same underlying reliability characteristics. Contracts mirrored this structure, combining energy payments based on marginal cost with demand payments tied to the fixed cost of the resource. Buyers were paying for physical assurance—capacity meant a resource stood ready to perform when needed, and its contribution was easy to quantify and track. The market did not need to explicitly price individual attributes like inertia or voltage support, because they were bundled into the resources being procured.

As the ISO and RTO markets evolved, efforts were made to adapt the capacity product. Installed Capacity (ICAP) became Unforced Capacity (UCAP). “Pay for performance” mechanisms were added to account for outages and incentivize reliability. But these additions only partially addressed the gap. System operators typically act to avoid shortage events that would trigger performance penalties, and when shortages do occur, high prices often provoke regulatory or political backlash. The intended discipline of scarcity pricing rarely materializes in practice.

At the same time, the supply mix has undergone a profound transformation. Today’s resource portfolio includes a broad array of technologies—wind, solar, battery storage, demand response—many of which lack the traditional reliability bundle. They may not be dispatchable, may not contribute to inertia or voltage regulation, and often lack fuel security. Some even introduce operational challenges, such as steep net load ramps caused by solar generation. While these resources advance decarbonization objectives, they are fundamentally misaligned with the original capacity construct and are difficult to reconcile with its design and intent.

Meanwhile, the rise of zero-marginal-cost resources has suppressed energy market prices, eroding the revenues available to conventional generators that still provide essential reliability services. Capacity payments were intended to fill this “missing money” gap, but rational price formation has proven elusive. Demand curves were introduced to create more stable investment signals, with prices designed to fluctuate around the net cost of new entry (Net CONE). Yet in practice, shortage pricing is rare, and

over time, prices have trended too low to support the retention of critical resources. Retirements of fuel-secure coal, oil, and nuclear units—driven by both economics and policy—have outpaced the system's ability to replace their reliability contributions.

Compounding this issue, new entry is increasingly driven by out-of-market mechanisms, including state mandates, procurement programs, and clean energy subsidies. These initiatives reflect legitimate public policy priorities, but they are not priced or coordinated within the capacity market framework. As a result, subsidized resources displace others in the market, driving down clearing prices and undermining the revenue streams needed to support resources that offer attributes critical to system stability but not recognized in current market designs.

In short, the capacity market has become unmoored from its original purpose. It no longer ensures that resources with the necessary reliability characteristics are retained or incentivized to enter the market. Instead, it rewards nameplate megawatts based primarily on their availability during peak periods, without regard for the broader system needs. The market construct must evolve to reflect today's operating realities—or risk failing to deliver the reliability it was designed to ensure.

IV. PROPOSED CAPACITY MARKET CHANGES ARE NECESSARY BUT NOT SUFFICIENT TO ENSURE SYSTEM SECURITY OR TO ADDRESS STRUCTURAL ISSUES

All of the conference discussion panels touched on a number of resource adequacy related changes the ISOs/ RTOs are considering for implementation. Many of these changes represent improvements but are not sufficient to deal with the magnitude of the anticipated reliability shortfall. Essentially, every area is either using or considering the implementation of an Effective Load Carrying Capability (ELCC) assessment in their resource adequacy process. Areas with capacity markets, such as PJM or ISO-NE, are considering the use of ELCC to qualify the amount of capacity a resource may sell into the market, and areas without explicit capacity markets, such as California, are either using it or proposing to do so in their resource adequacy assessments.

The move to ELCC, particularly marginal ELCC, does address a number of areas of concern. The ELCC process evaluates the ability of a resource to meet system adequacy needs over a wider range of operating hours, which captures some of concerns with fuel limitations or intermittent operation. ELCC also addresses correlated outages among resource types, such as wind or solar, and addresses the declining reliability contribution of additions of outage correlated resources to the system. Many questions remain unresolved, such as the debate as to whether ELCC for a resource class should be

calculated as a class average discount factor or as the value of the marginal new resource.

In addition, resources within the same class may perform very differently from each other. A combined cycle "class" may contain very new resources and very old resources of the same type with very different contributions to reliability, begging the question as to whether the ELCC rating should be resource specific. This is not an argument for maintaining the rating status quo, since use of ELCC is an improvement, but overall, the improvement is not substantial and only addresses a portion of the reliability question.

Likewise, the move from a forward capacity market to a prompt seasonal market, as discussed by PJM and ISO-NE, may better reflect the value of fuel security and may incentivize contracting for existing fuel infrastructure; however, it is unlikely to incentivize significant investment in incremental fuel infrastructure. As discussed at the conference, developers of gas pipelines typically seek extended contract commitments of ten years or more, and it is not clear that resource owners will be willing to make such commitments based on a seasonal clearing price.

These potential changes, ELCC and market timing, attempt to improve the adequacy component of reliability but do not address the other aspects of system reliability and security, and do not address any of the structural problems currently facing the power grid. While the defined capacity product initially did a reasonable job of encompassing system reliability, the entry of very diverse supply technologies has created a situation where there is no good way to address all the reliability and security attributes needed to operate the power system in a single product like capacity, or even in a set of markets or payment streams.

It is possible to disaggregate the elements of system reliability into discrete component parts. This would require specific product definitions, and the identification of rights and obligations associated with the service. Some could be grouped into product aggregations, while others may need to stand alone. Purchase quantities for each product would need to be identified along with locational requirements if applicable. Resource product qualification, offer requirements, pricing rules and price formation, market power mitigation, and performance penalties would need to be defined, creating a set of what would look like capacity market tranches.

While all this could be done it would be incredibly complex, and the interactions between the capacity market, to the extent it remains as the adequacy measure, and the individual products themselves are interdependent. Like capacity, many of the reliability attributes

arise from the physical characteristics of the various technology types and there is no incremental cost to provide the service.

With resources providing different attributes, it would be challenging to jointly optimize market clearing. A resource such as wind may not provide many of the needed reliability attributes, but it does provide inexpensive energy. Another resource, such as gas combined cycle, may provide many of the reliability attributes but it may provide expensive energy. An optimization process would need to procure a portfolio meeting all the defined reliability requirements, but no single clearing price could exist.

The capacity market demand curve is anchored on the net cost of new entry, but in this set of attribute markets, what is the new entrant? Which reliability attributes does it supply and how much does it earn from each of these markets? The reliability attributes could be procured in a series of markets and somehow jointly optimized, or they might be procured as additional constraints in a single reliability market.

The NYISO is currently considering capacity market changes, among them is a concept referred to as an "attribute-based capacity market" (ABCM). Conceptually, NYISO would define capacity attributes such as operating duration, availability during specific hours, flexibility and ramping capability, locational attributes, and others. Resource capacity accreditation would be based on these attributes with the goal that capacity prices would reflect the value of each attribute rather than just installed capacity.

While the ABCM would seem to codify the above discussion, all the issues, complicated interactions, and questions regarding price formation and clearing prices remain. It should be noted that in its initial proposed clearing process for the forward capacity market in 2005, PJM considered a somewhat similar approach. Rather than an explicit attribute-based qualification, PJM proposed enforcing the purchase of additional reliability attributes as constraints in its capacity clearing process. That approach was dropped when stakeholders raised the concerns expressed above and PJM instead went with a simple marginal clearing of the UCAP capacity product.

RTOs with capacity markets have spent more than two decades trying to use the defined capacity product to ensure system adequacy and security—through continuous adjustments and, at times, wholesale redesigns aimed at keeping pace with changing supply technologies. While some of the proposed reforms may offer incremental improvements, they are, at this stage, insufficient. Projected growth in data center load and electrification is expected to drive dramatic increases in demand across all regions within the next five to ten years. Yet the current slate of resource adequacy market reforms is unlikely to be fully implemented before 2028–2030, if at all.

A price signal in 2030 is not likely to result in increased supply much before 2035, meanwhile existing resources are under financial pressure and may retire. Stakeholders in New York have recently requested NYISO to develop a 'retention market' separate from the capacity market in an effort to prevent existing resources from retiring faster than they can be replaced. Action is needed now to ensure all ISO/RTO regions successfully accommodate the projected load growth, and solutions cannot wait ten years. The situation brings to mind "Occam's Razor," the principle that all else being equal, the simplest solution is usually the best.

V. NONE OF THE PROPOSED MARKET CHANGES OR IMPROVEMENTS ADDRESSES THE NEED FOR BILATERAL CONTRACTING OR THE URGENCY OF LOAD GROWTH

Despite the range of proposed market reforms discussed during the technical conference, none directly addresses a foundational issue: the need to strengthen bilateral contracting as a tool for ensuring reliability amid rapidly accelerating load growth. This omission is significant. A relative point of consensus across the conference panels was that bilateral contracting remains not only desirable but essential for supporting long-term investment and system planning. In fact, the original design of capacity markets, such as PJM's Reliability Pricing Model, envisioned the capacity market as a backstop mechanism, intended to procure residual needs not already met through bilateral contracts. Over time, however, the market has evolved in a way that places too much reliance on short-term, centralized procurement—leaving the system more exposed to both investment uncertainty and volatility.

Bilateral contracts offer important benefits to both load-serving entities (LSEs) and resource developers. For LSEs, contracting helps to stabilize prices over time, reducing exposure to short-term price spikes that may not reflect the long-run cost-of-service. For suppliers, bilateral agreements provide revenue certainty and bankability—critical factors in securing financing and making capital-intensive investments. This type of contracting can also unlock additional reliability value by enabling longer-term decisions, such as firming up fuel supply arrangements, investing in pipeline capacity, or enhancing operational flexibility. Without this foundation, many developers are reluctant to commit to large-scale investments, especially when future market conditions are uncertain or subject to frequent redesign.

Unfortunately, current market designs and regulatory structures often discourage such long-term arrangements. Continued changes to capacity market rules, evolving state and federal policies, and the lack of clearly defined long-term obligations for load contribute to a climate of regulatory and investment uncertainty. In many jurisdictions,

LSEs do not have a durable obligation to procure capacity on a long-term basis, nor are they incentivized to do so. Moreover, some state-administered procurement programs, such as standard offer service or default service auctions, are explicitly structured around short-term contracts, further reducing the incentive to pursue bilateral agreements that align with system needs over the long-term.

The challenges are particularly acute for LSEs serving small and medium-sized customers. While large industrial loads, such as data centers, may have the scale and creditworthiness to enter into long-term bilateral contracts directly with suppliers, most smaller LSEs operate under shorter planning horizons and are constrained by regulatory frameworks that prioritize short-term cost minimization. This creates a mismatch between the long-term reliability investments the system needs and the short-term procurement signals that dominate current market behavior. As a result, many of the resources now entering the interconnection queues are doing so without any long-term revenue certainty, raising questions about whether and how they will ultimately deliver reliability value to the system.

To ensure that markets keep pace with growing demand and the evolving reliability landscape, reforms must go beyond capacity market design and explicitly consider how to enable and incentivize bilateral contracting. This could include clarifying long-term obligations for LSEs, adjusting procurement structures to accommodate multi-year contracting, and reducing regulatory and market uncertainty that currently deters these agreements. Without a more intentional framework to support bilateral contracting, the system will remain overly dependent on short-term market signals that are ill-suited to meeting long-term reliability challenges.

VI. POTENTIAL SOLUTIONS TO SUPPORT LONG-TERM RELIABILITY

The technical conference highlighted growing concerns about the ability of current market structures to support long-term reliability and resource adequacy, particularly in light of rapid load growth, changing resource mix, and declining investment certainty. Several potential solutions were raised during the discussion, and there is merit in exploring multiple pathways simultaneously. These options include (a) mandating contracting obligations for load-serving entities, (b) enabling central procurement through a power authority, and (c) returning to utility-owned generation under cost-of-service regulation. Each of these solutions addresses the fundamental need to create a durable, enforceable framework for securing long-term capacity resources.

a. Mandatory Contracting Requirement for Load-Serving Entities

One of the more direct solutions would be to require LSEs to contract for their share of system reliability needs, including capacity and other essential reliability services. This question was explicitly posed by Commissioner Mark Christie during the technical conference and garnered attention across multiple panels. Several regions already assign some form of obligation to LSEs. For example, SPP operates under a traditional cost-of-service (COS) utility model in which vertically integrated utilities are responsible for planning and procuring sufficient resources to serve their load. In California, the Resource Adequacy program requires LSEs to demonstrate that they have secured forward contracts covering their capacity obligations, subject to compliance filings and penalties for non-performance.

MISO also places capacity obligations on LSEs, but it does not currently require them to demonstrate specific bilateral contracts. Instead, obligations can be met through participation in the Planning Resource Auction (PRA), bilateral transactions, or self-supply. However, the lack of a firm contract demonstration requirement leaves uncertainty about whether LSEs are making the types of long-term commitments that support timely resource development.

A more standardized approach could involve assigning reliability procurement obligations directly to transmission owners, many of which are vertically integrated and already participate in resource planning. Alternatively, a national framework—potentially through FERC—could require RTOs to work with state commissions to enforce LSE contracting obligations at the retail level. This hybrid model would preserve state authority over retail providers while ensuring that all LSEs contribute proportionally to long-term system reliability. Such a framework would need to account for differences in state regulation, competitive retail structures, and existing planning processes, but could bring greater uniformity and accountability to a fragmented resource adequacy landscape.

b. Central Procurement Through a Power Authority

Another potential approach would involve the establishment or expansion of a regional or national power authority with the mandate to conduct central procurement for capacity and reliability services. A power authority could work closely with RTOs to identify long-term capacity needs, determine locational requirements, and contract for resources accordingly. This entity would not necessarily need to own the generation—it could serve as a centralized buyer of reliability services, executing contracts with merchant resources that continue to operate in energy and ancillary services markets.

This “hybrid” model would preserve the benefits of competitive markets, such as efficiency, innovation, and customer choice, while providing a stable investment signal for resources that offer long-term reliability value but may struggle to recover fixed costs through energy market revenues alone. The authority could issue solicitations based on criteria developed in collaboration with RTOs, states, and reliability coordinators, with contract terms tailored to ensure deliverability, operational performance, and fuel security. Similar models exist in other sectors; for example, ISO New England’s Forward Capacity Market includes a central procurement mechanism, and the New York Power Authority (NYPA) has successfully executed long-term contracts for both public and private customers.

This solution could be particularly valuable in regions with competitive retail markets or fragmented utility footprints, where no single LSE has the incentive or obligation to procure long-term resources. A power authority could also mitigate “free rider” concerns by allocating the costs of procured resources across the system in proportion to reliability contributions or load share. However, the governance structure of such an entity requires careful design to ensure transparency, stakeholder engagement, and alignment with public policy goals.

c. Return to Utility-Owned Generation Under Cost-of-Service Regulation

Finally, in some jurisdictions, the most practical solution may be to return to greater reliance on utility-owned generation procured through integrated resource planning and recovered through traditional cost-of-service regulation. This approach has long been the foundation of reliability in vertically integrated systems and remains a key component of resource adequacy in regions such as the Southeast and parts of the West.

Utility ownership under cost-of-service provides several advantages. It ensures alignment between planning, procurement, and system operations; allows for regulatory oversight of investment decisions; and provides a clear mechanism for cost recovery. It also removes the need to structure long-term contracts with third parties, which can be administratively burdensome or difficult to secure under current market conditions. For resources with long development timelines or high upfront capital costs, such as nuclear, geothermal, or carbon capture project, cost-of-service treatment may be the only viable path to deployment.

However, returning to this model on a scale would represent a significant shift for regions that have restructured their electricity sectors around competitive markets. In these areas, any move toward utility ownership would need to be carefully justified in terms of reliability need, market failure, or public interest. Policymakers may also wish to explore

hybrid approaches, where utilities develop and own a portion of new capacity to meet reliability requirements, while markets continue to support competition for remaining needs.

VII. CONCLUSION

The issues discussed throughout the technical conference make clear that incremental adjustments to existing market designs will not be sufficient to meet the reliability challenges of the coming decade. The current capacity constructs in many RTO and ISO regions are no longer capable of delivering the outcomes they were designed to support. Market reforms that merely tweak auction parameters or revise accreditation rules fail to address the more fundamental limitations, most notably, the disconnect between short-term price signals and long-term reliability needs. In a power system facing rapid demand growth, an evolving generation mix, and increasing reliability threats, more comprehensive and structural reforms are urgently needed.

What is required now is a fundamental rethinking of how we plan for and procure capacity. At the core of this reform must be a stronger commitment to centralized planning. A purely market-based approach, especially one that relies on residual mechanisms like capacity auctions, cannot be expected to deliver a balanced, reliable, and clean portfolio of resources. Centralized planning—whether conducted by RTOs, states, or coordinated regional entities—offers a framework for aligning long-term system needs with infrastructure investment. It can help identify resource attributes that markets undervalue, address geographic and locational constraints, and ensure that emerging reliability and decarbonization challenges are considered holistically.

In parallel with better planning, a corresponding shift toward central procurement may be necessary to ensure that reliability needs are actually met in practice. Several models already exist. In California, the Resource Adequacy program assigns forward obligations to LSEs, which must demonstrate they have secured sufficient resources through contracts or ownership. MISO's seasonal construct also relies on a form of central assessment of resource adequacy, though the actual procurement is left to individual entities. These approaches suggest that hybrid models—combining centralized needs assessments with flexible procurement tools—may provide a workable middle ground. A central procurement entity, such as a regional power authority, could also play a role where the LSE landscape is fragmented or where state policies require greater coordination with wholesale market functions.

The stakes are high. Without decisive structural reform, the risk of capacity shortfalls and system instability will continue to grow.

Resource adequacy must be viewed not simply as a compliance obligation or market product, but as a core function of system planning and operations. The path forward must integrate reliability, decarbonization, and affordability elements in a manner that markets alone cannot deliver. FERC, states, and RTOs all have a role to play in this transition, and success will require close coordination across institutional boundaries.

In sum, ensuring long-term reliability in today's rapidly changing energy landscape demands bold action—not just adjustments around the edges. Embracing centralized planning, establishing clear procurement responsibilities, and rethinking the capacity construct itself are essential steps toward building a more resilient, efficient, and forward-looking electricity system.