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Rethinking Capacity Markets

A pragmatic new approach to assuring reliability.

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The Federal Energy Regulatory Commission (FERC) recently issued a deficiency notice that halted the latest reforms proposed by the PJM Interconnection for its regional capacity market—reforms that would rewrite a key market power rule, the Minimum Offer Price Rule or "MOPR," that targets state programs to develop new generation resources.

This round of changes to PJM's buyer-side mitigation rule could prevent these states' load-serving entities from relying on the capacity that certain new, gas-fired generation resources provide, by precluding these resources from clearing in the capacity market.

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FERC's notice suggests that it might be concerned that the proposed changes have finally gone too far. But FERC may yet decide to accept PJM's proposal, allowing PJM to proceed with implementing the changes in time for the next annual auction. Regardless of how this current dispute ends, these repeated rounds of so-called "reforms" have made rules like the MOPR so convoluted that the resulting market rates can't comport with the Federal Power Act's "just and reasonable" mandate. Furthermore, a decade of experience is proving that these market designs can't assure customer access to adequate, reliable supplies of electric generation capacity.

It's time for FERC to consider alternative approaches to the current centralized capacity market designs if it is to effectively provide customers with electric reliability at just and reasonable rates.

A Bit of History

A little more than a decade ago, FERC directed regional grid operators to propose significant changes to the capacity markets they administered. A driving force underlying the redesign was the perception that prices in these markets were too volatile and wouldn't support needed investment in generation capacity. Regional operators proposed new capacity market designs in the northeast, first for New York and New England and, later, in PJM's mid-Atlantic region.

FERC permitted each region to develop its own designs. New York selected a proxy demand curve to price a short-term capacity product and established separate capacity zones corresponding with transmission-constrained load pockets. New England proposed locational installed capacity (LICAP), an approach similar to the New York design, but states and market participants representing customer interests strongly opposed this proposal. Following a highly unusual oral argument before FERC, the commissioners directed the New England parties to begin settlement proceedings in order to develop an alternative. The outcome was a market design for a three-year forward, locational capacity product with prices set by a descending clock auction (not a demand curve) to procure the level of capacity needed for reliability (and not more. PJM adopted New York's demand curve concept, but combined it with New England's forward obligation capacity product to create its own unique design.

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Each of these proposals sought to assure electric reliability, a public policy objective designed for the benefit of electric customers. FERChas addressed this objective by encouraging regional grid operators to establish centralized markets to buy and sell capacity: establishing the amount of capacity needed to maintain reliability, and defining a capacity product with elements similar to an energy call option. In our view, however, FERC's experimental capacity market reforms haven't served the reliability interests of customers. After a decade of experience, these market designs aren't providing customers with any real certainty that sufficient electric capacity of the type needed will be available to keep the lights on at a reasonable, stable price over the long term.

Importantly, FERC selected these market designs specifically to support new investment necessary to address both immediate and long-term reliability concerns. In New England, for example, FERC found that significant capacity shortages in southwestern Connecticut and northeastern Massachusetts load pockets justified a need for LICAP. FERC expected that higher, more stable capacity revenues would reduce the financing risks and costs of new investment in generation capacity, and reduce consumer costs at the same time. But the redesigned markets haven't proved capable of addressing long-term reliability needs—needs that can be met only through the addition of new generation capacity.

For example, since implementation, PJM's forward capacity market hasn't supported any significant investment in new generation necessary for long-term reliability where it's most needed, in transmission-constrained load pockets like New Jersey and Maryland. Now PJM must rely on reliability-must-run (RMR) contracts—the blatantly out-of-market stop gap that had triggered the initial development of regional capacity markets—so as to keep certain generation facilities in Pennsylvania and Ohio from being retired while waiting for transmission upgrades to relieve congestion in the Midwest. Because the capacity market has little prospect to produce the new investment necessary to replace retiring coal-fired generation plants, we expect PJM to increase its reliance on out-of-market RMRs to maintain reliability by delaying the retirement of these resources.

The notion that capacity markets of this type can support new, merchant investment in generation capacity is faulty because the current market designs omit essential elements. For example, the market provides only short-term revenue assurance—no more than three years—even though investment decisions (and accompanying financing) require longer-term certainty (say, 20 years). Consequently, reasonable financing terms are unavailable or larded with risk premiums for a merchant developer that eschews a long-term power purchase agreement but instead relies on the regional market.

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This isn't to suggest that FERC's market design experiment has been a total waste. To the contrary, these regional markets did provide some near-term reliability benefits initially, by capturing low-hanging fruit like deferring planned generation retirements and adding incremental generation capacity to existing plants, as well as creating new demand response capacity. In some regions, New England particularly, a flood of new demand response resources has measurably increased the quantity of available capacity to surplus levels well beyond the region's installed capacity requirement. Even though the market rules treat these types of capacity comparably with generation capacity, these resources mostly defer and can't fully replace the eventual need for new generation capacity. FERC expected markets to produce new investment in generation capacity, but that hasn't happened. "Iron in the ground" capacity is needed to provide longer-term reliability for customers, and it would be risky to assume that near-term reliability stop-gaps are indicative of any capacity markets' success over the next decade.

Why Capacity Markets Have Failed

While failing to assure their most fundamental reliability objective, FERC's capacity markets have evolved over time to become progressively more inconsistent with customer interests in other ways as well. This unfortunate evolution impedes resource diversity, creates granular but unreliable price signals, and relies too heavily on administrative constructs to arrive at a so-called market price.

First, FERC has accepted changes to buyer-side market power rules like the MOPR that interfere with the ability of load-serving entities to build or contract for new capacity outside of these regional markets. Such rule changes create unreasonable, overbroad barriers to entry that are intended to ensure that self-supplied, new capacity resources won't clear the auction, except at very high prices. Historically, load-serving entities relied on capacity from supplies that they owned or obtained through bilateral contracts, and turned to purchases only for their residual requirements, through a regionally administered spot market. This allowed load-serving entities to build capacity portfolios with diverse resources that met their customer service and public policy objectives, *e.g.,* to hedge against future price volatility, to provide fuel and ownership diversity, and to invest in renewables. Now, if some stakeholders get their way, it will be too risky for some load-serving entities to undertake their own investments in new capacity resources to satisfy their share of capacity obligations, forcing them to abandon long-standing business practices and overriding their own determinations about types and mixes in their capacity portfolio that best serve their customers' interests.

Second, FERC has encouraged market design changes to improve locational price signals under a theory that the prices provide project developers with valuable information about the preferable locations for and timing of potential investments. Rules establishing numerous capacity zones in order to create this granularity, however, have counterproductively increased price levels and volatility without attracting needed investment. More capacity zones means smaller markets so that suppliers' bidding strategies, lumpy changes in capacity supplies, and the administrative hand (not the invisible hand) through new or changed rules and procedures have a greater effect on capacity prices. Capacity prices have proven to be most volatile in small zones where investment is most needed, but volatile prices don't send accurate signals or provide the predictable long-term revenues needed to finance significant new investment. In sum, locational markets don't support locational investment.

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Third, capacity markets haven't served customers' interests because FERC has approved rules that fix the market price based largely on administrative parameters, not competitive outcomes. The grid operator prepares these administrative parameters—such as the CONE benchmark for cost-of-new-entry, and calculated offsets for energy and ancillary services revenues—without regard to developer experience, decisions, and analysis. PJM's latest round of MOPR changes requires resources that fit within this rule to submit a proxy offer reflecting PJM's rote estimates for the cost of a generic plant. If FERC approves this rule, a resource wouldn't be allowed to offer capacity at a price based on its own costs, even when its costs are demonstrably lower than an administrative estimate that PJM's chief economist has publicly acknowledged is too high. Additionally, the misplaced enthusiasm for administrative proxies has relieved FERC and industry participants from the responsibility to measure and understand the value customers place on electric reliability. Since there's still no practical or accurate way to measure the value that customers assign to electric reliability, the markets continue to be controlled by crude estimates of the necessary capacity.

State Concerns Go Unaddressed

After several years of experience, FERC's capacity experiment has demonstrated that these regional markets can't fulfill their public policy purpose of assuring reliability for customers. These markets are unable to support, when needed, the new merchant investment necessary for reliability. Of particular concern is investment in baseload and intermediate capacity that's needed to match anticipated load growth. This persistent investment gap has been alarming to some retail-choice states, such as Maryland and New Jersey. Both states have been grappling with forecasts of material capacity shortages. Despite capacity prices persistently higher in these states than elsewhere in PJM, there's been no significant new investment in generation capacity.

FERC has resolutely insisted that capacity market price signals work, but that hasn't assuaged these states' concerns, because years of high prices haven't stimulated new investment to serve load pockets. If the markets functioned as intended, new investment would have occurred. Because high prices—albeit in a very short-term, volatile market—weren't producing new investment, state legislators and regulators challenged FERC to explain what customers in constrained regions were getting in return for rates that far exceeded those in other regions.

Maryland and New Jersey regulators in particular have had to grapple with a difficult choice: do nothing but hope the capacity investment will be forthcoming through the wholesale market, or take action. Rather than passively acceding to their fate, Maryland and New Jersey acted to address capacity deficiencies that created reliability risks.

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Following legislative authorization, the Maryland PSC proceeded through a lengthy, deliberate process to direct the state's electric utilities to enter into long-term contracts for new generation resources. Although proceedings opened in 2009 to investigate the need for new capacity and to decide the mechanism for doing so, it took more than two years to issue an order selecting a 660-MW combined-cycle facility and directing state utilities to enter into a contract with the new resource. Had a new merchant developer announced during this interval that it intended to build, relying solely on PJM's capacity market, the Maryland PSC might not have proceeded.

Likewise, in early 2011, New Jersey enacted new legislation establishing a pilot program to develop new baseload and intermediate generation capacity needed for reliability. The legislation directed the Board of Public Utilities to implement a competitive procurement, with the winners entering into long-term power purchase agreements with utilities. The BPU selected three new gas-fired, combined cycle plants totaling 1,949 MW.

The New Jersey and Maryland initiatives prompted a slew of litigation before FERC—and federal courts—even before the state agencies had issued competitive solicitations seeking new capacity. FERC was swayed by complainants' theory that the state initiatives were an exercise of buyer-side market power. As this hypothesis goes, the states allegedly subsidize investment in new, high-cost generation in order to suppress capacity prices and lower electricity costs for state customers. Concluding that state-initiated resources would affect capacity prices, FERC revised the buyer-side mitigation rule to eliminate a narrow exemption allowing entry by state-initiated resources for reliability reasons. FERC's decision has been appealed and is presently under review by the U.S. Court of Appeals for the Third Circuit.

Perhaps because the Maryland plant and two of the three New Jersey plants cleared the PJM capacity auction unexpectedly, or perhaps because FERC's response to state initiatives to assure reliability in prior proceedings never meaningfully addressed the reliability concerns compelling these states to act, PJM filed another proposal of buyer-side mitigation rule changes in December 2012 that again aggressively targeted the development of new generation resources through state programs. This new proposal, developed during secret negotiations that excluded state regulatory commissions, was intended to exclude from the market any new gas-fired generation resource developed through a non-compliant state process. A state solicitation to address a reliability need that limits qualifying responses to new, incremental capacity would fail the rule, thus triggering mitigation. Resources thus mitigated wouldn't be allowed to compete with a cost-based offer to enter the market. Instead, they would be allowed to offer only at a rate that matches a generic estimate of the cost of new entry—an estimate that PJM's chief economist agrees substantially exceeds a cost-based offer.

These proposed MOPR reforms have been halted temporarily because FERC issued a deficiency notice to PJM, requiring more information about its proposal and specifically requiring PJM to explain "why it is reasonable" to require a resource to submit "the default offer price" when it "may have lower competitive costs." FERC's notice intimates that the agency might be concerned that the proposed changes have finally gone too far. But FERC's decision can't be predicted, and it might decide to accept PJM's proposal, allowing PJM to implement the changes in time for the next annual capacity auction. If approved, this proposal will fundamentally change the rule's purpose, but these changes won't help FERC achieve its public policy objective of providing customers with reliable electric energy supplies at a reasonable price through capacity markets.

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One thing is certain from this history: in highly regulated markets like these capacity markets, the prospect for substantial gains will create pressures for rules changes that diverge from competitive norms. As key rules evolve to advantage specific interests, competition's expected benefits give way to high prices and efficiency losses. Repeated rounds of so-called "reforms" to key rules in wholesale capacity markets have caused some rules to become so convoluted that rates in these markets can't comport with the Federal Power Act's just and reasonable mandate. The MOPR doesn't address genuine buyer-side market power, and its minimum offer price requirement props up prices by blocking newentry for existing suppliers' benefit. Given the developing morass, FERC should consider alternative approaches to the current centralized capacity market designs if it is to effectively protect customers and assure just and reasonable rates. Now is a good time to explore a new design that places primacy on reliability at a reasonable price—one that won't interfere with the ability of load-serving entities to select the capacity resources that best meet their needs, whether provided through self-supply or a residual spot market.

Characteristics of an Alternative Approach

We propose that a market design alternative meet the following objectives:

- Address system reliability concerns in advance by facilitating investment in new generation capacity resources, which will avoid resorting to long-term out-of-market RMR contracts;
- Maintain economical, existing generation capacity resources with rates that are just and reasonable, but not so excessive as to prop up inefficient or expensive generation plants;
- Allow capacity buyers to make capacity purchasing decisions that achieve public policy objectives and meet their customers' requirements; and
- Ensure committed capacity resources' performance when needed, *e.g.*, by compensating only those resources that actually provide reliability services.

The proposed alternative centers on bilateral contracting—but with residual markets to balance parties' positions. We recommend abandoning the increasingly centralized market approach preferred by some regional transmission organizations. Centralized markets are progressively resorting to unduly restrictive rules that both dictate how load-serving entities assure their customers of reliability and unnecessarily impede states' efforts to achieve public policy objectives. Rules that ratchet down opportunities for free exchange and that unreasonably limit choice won't serve suppliers or customers in the long run. The centralized market approach also necessarily reduces capacity to a unidimensional commodity, which it isn't. Capacity has different qualities, and buyers have different requirements. Moreover, system planners agree that resource diversity—which current capacity markets ignore—is essential for system reliability.

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Our alternative proposal rejects heavy-handed purchasing requirements and eliminates the risk that load-serving entities won't be able to satisfy their capacity obligations with their own resources. Instead, it respects decisions by load-serving entities regarding their capacity portfolios—decisions they make to best serve the interests of their customers. Load-serving entities are allowed to self-supply through their own resources, long-term contracts, and short-term obligations, or to procure capacity in residual markets administered by the grid operator. They may use any combination of their own generation assets, demand response resources, energy efficiency, transmission, and capacity contracts to meet their share of regional capacity obligations. They may contract with capacity resources developed to achieve public policy goals, *e.g.,* renewables. All capacity is subject to deliverability, performance, and other reliability-based criteria.

This alternative approach revives and reinvigorates the forward-looking integrated resource planning process to identify new generation or transmission resources needed to resolve anticipated reliability issues. It abandons the notion that reliability needs for new generation resources can be identified through capacity market price signals, since prices in these highly regulated markets are neither transparent nor reliable. Engineering studies performed in connection with integrated resource planning (which already form the basis for capacity zone determinations anyway) are likely to do a better job indirectly identifying reliability needs.

The integrated resource planning process we envision is an enhancement of the processes already used by grid operators for transmission planning, but modified to include generation as well as transmission solutions for reliability concerns.[1] A generation solution would identify the interconnection point (or points) and specify other necessary or desirable characteristics. Interconnection rules would be amended to allow these projects to fast-track through the interconnection process. Since interconnection costs can be a significant unknown and an impediment to project development, predictable costs for network upgrades would provide needed certainty for project developers.

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The specifications developed in the planning process for new generation resources would form the basis for competitive procurement administered by the grid operator or a state agency. Developers would compete to build and operate a plant that complies with the specifications. The winner might be awarded a capacity contract of 10 years' duration or even longer. The competition might take the form of a traditional request for proposals or another process such as a descending clock auction, which starts at a high price and progressively drops until only one bidder remains. Load-serving entities may contract with potential new resources for some or all of their capacity, even in advance of the auction.

An integrated resource planning process would require stakeholder buy-in, plus the support of state regulators. States likely wouldn't tolerate a process that didn't proactively resolve identified reliability concerns.

The proposed alternative approach also recognizes the value that existing capacity resources provide to system reliability, along with the value contributed by new merchant capacity developed outside of the integrated resource planning process. These resources would also compete for bilateral contracting opportunities with load-serving entities, and also could sell capacity in periodic auctions administered by the grid operator. There might be benefits to changing the forward characteristics and the duration of the capacity product to a longer or shorter period. For instance, a longer commitment period might provide more predictable revenues for merchant plants and also allow a longer regional planning process to extend the planning horizon. To the extent that there might be long-term benefits with more stable prices, the primary auction might incorporate a sloped demand curve tied to actual offers or a price collar. Capacity resources may exit the auction to retire, to export capacity, or when prices drop below the threshold level providing for recovery of going-forward costs. We see a benefit as well to a shorter-term residual auction, without price protections, allowing capacity buyers and sellers to perfect their positions before the commitment period. A robust bilateral market, combined with a longer-term primary residual capacity auction and a shorter-term reconfiguration auction, would provide just and reasonable capacity rates and terms for capacity suppliers and buyers. In addition, it might be time to consider related market rule changes that would more closely integrate energy and capacity markets, such as raising the energy offer price cap.

Debates about the best approach to reliability have proved highly controversial. The current iteration of capacity market designs won't support investment in generation capacity when needed, and the current trend to implement rules that prohibit self-supply and that prohibit states from taking action to assure reliability is, at best, short-sighted. An alternative proposal—which will benefit from rigorous debate in fleshing out its details—might not address the needs of every market participant. But finding common ground on the principles that we propose is an essential first step to an important conversation about the way FERC achieves its public policy objective of assuring reliability for customers.

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[1] . We aren't proposing a generation solution to address system upgrades for economic or public policy reasons.