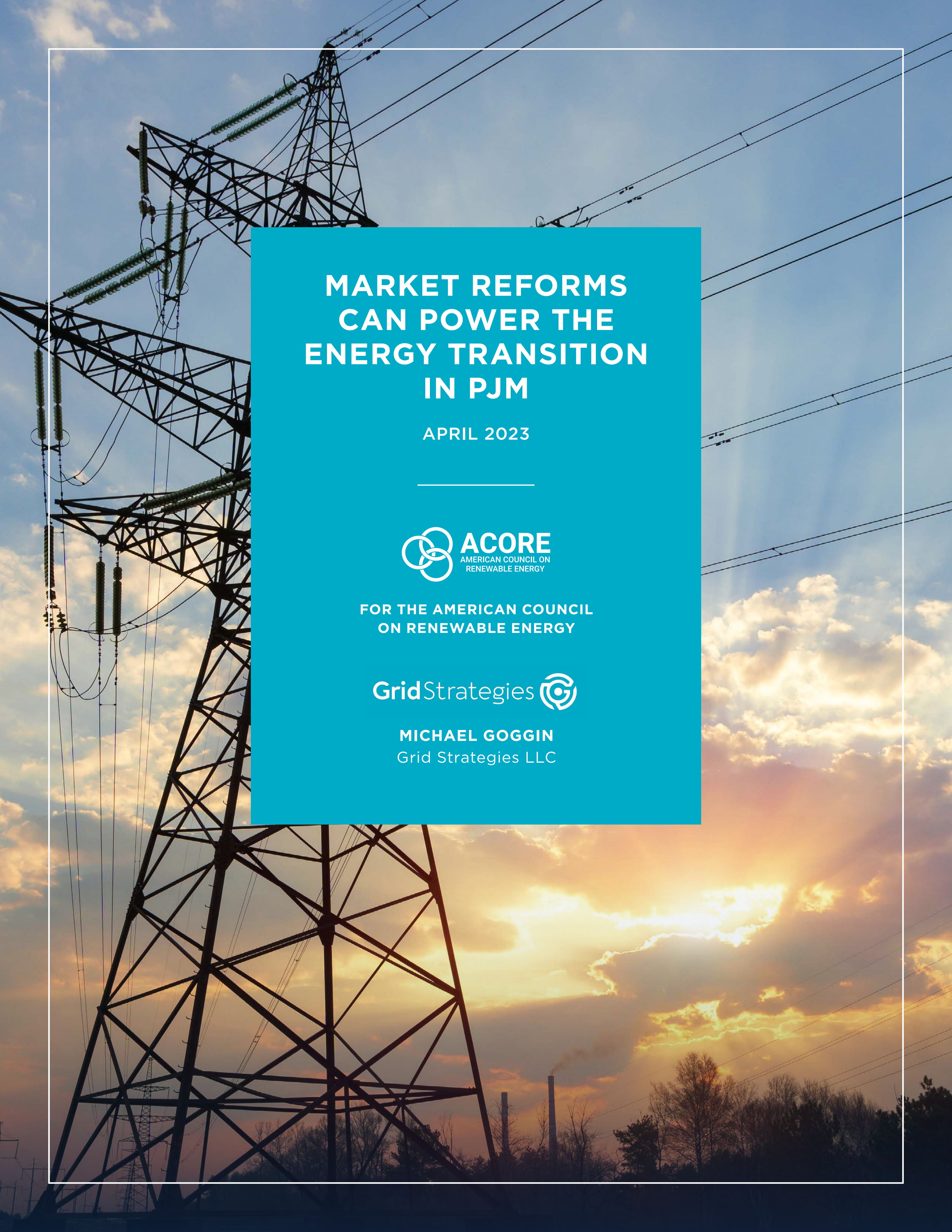

MARKET REFORMS CAN POWER THE ENERGY TRANSITION IN PJM

APRIL 2023

ACORE
AMERICAN COUNCIL ON RENEWABLE ENERGY

FOR THE AMERICAN COUNCIL ON RENEWABLE ENERGY

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EXECUTIVE SUMMARY

Wind, solar, and battery storage resources can revolutionize how grid operators keep the lights on, thanks to their power electronics, fast controls, and other advanced technologies. Electricity market rules play an essential role in unleashing those capabilities while ensuring an orderly transition from today's resources and operating practices. This report recommends reforms that will create a level playing field in the market for any resource that can provide needed services, facilitating a reliable and efficient transition to new resources. These recommendations seek to maximize the use of markets, recognizing that well-designed markets are the most efficient way to aggregate dispersed information and translate it into a price signal for performance that reflects the value of reliability. We encourage states and other stakeholders to work with PJM to implement these reforms.

This report primarily focuses on reforms that can be implemented by the PJM Interconnection LLC ("PJM"), which operates the wholesale electricity market and power grid for all or part of 13 Great Lakes and Mid-Atlantic states stretching from Illinois to Virginia, while a companion report focuses on the Midcontinent Independent System Operator ("MISO") region to its west. However, many of these recommendations are broadly applicable in all regions, as grid operators across the country are seeing similar changes in their generation mixes and market needs due to the same fundamental economic and technological factors. More detail on these recommendations, as well as similar recommendations for the California Independent System Operator, can be found in comments ACORE and other clean energy organizations filed on January 18, 2023, in the Federal Energy Regulatory Commission's ("FERC's") Docket No. AD21-10-000 on modernizing wholesale electricity market design.[1]

1 Available at https://acore.org/clean-energy-associations-comments-on-energy-ancillary-service-markets/.

These comments offer the following recommendations for reforms PJM can implement:

I. Use markets to reduce out-of-market actions, and ensure that the market rules do not reward resources for their inflexibility

a. More accurately characterize the capabilities of all resources in the energy market, but do not reward inflexibility

b. Adopt more efficient unit commitment processes

c. If needed, create new markets or market products

II. Increase energy market price caps to better reflect the value of reliability and incentivize real-time performance and flexibility

III. Improve market transparency and efficiency by using more direct mechanisms to counter market power

IV. Improve transmission utilization both within PJM and at seams with neighboring grid operators to decrease congestion costs, curtailment, and market power

V. Reduce over-procurement in PJM's capacity market to strengthen energy market price signals

The recommendations will further improve PJM's efficient energy and ancillary services markets and operating practices. Most electricity is purchased through bilateral contracts outside the centralized wholesale markets, but the prices in wholesale markets provide the economic foundation for all electricity transactions. As a result, it is essential for those markets to send efficient price signals, which the reforms discussed above to improve operations, minimize inflexibility, and avoid over procurement are designed to achieve. For further background on these recommendations, we point to a comprehensive list of recommended market design changes we published several years ago,[2] with specific recommendations for PJM.[3]

2 Wind-Solar Alliance, "Customer Focused and Clean – Power Markets for the Future" (November 2018) at 5, available at: https://gridprogress.files.wordpress.com/2019/03/power-markets-for-the-future-full-report.pdf.

3 Wind Solar Alliance, "Customer Focused and Clean – Power Markets for the Future – PJM FOCUS" (Nov. 2018), available at: https://gridprogress.files.wordpress.com/2019/03/power-markets-for-the-future-pjm-focus.pdf.

I. USE MARKETS TO REPLACE OUT-OF-MARKET ACTIONS

PJM's filing in FERC's proceeding on market design,[4] as well as the PJM Market Monitoring Unit's ("MMU's") annual list of recommended reforms to market design,[5] correctly highlight the benefits of using markets to the maximum extent possible to replace out-of-market operator actions and compensation mechanisms affecting generator commitment and dispatch. While some operator actions and out-of-market compensation will still be needed, there are benefits from maximizing the use of markets because well-functioning markets efficiently and fairly drive generator behavior, while out-of-market payments distort prices and incentives.[6] The mechanisms for moving these actions into markets include: **(1) more accurate characterization of the capabilities of all resources in the energy and ancillary services markets; (2) more efficient unit commitment processes; and (3) the potential creation of new markets or market products**. To better understand what market reforms are needed, it is also important for PJM to keep better records of the factors driving out-of-market actions and payments (known as "uplift").[7] There should be transparency regarding the reasons for out-of-market payments so that stakeholders and market participants are confident that the prices reflect market conditions and that the market is operating efficiently.

A. Better characterize resources' capabilities, but do not reward inflexibility

We offer the following five principles for how resources should be characterized in commitment and dispatch decisions.

1. Ensure accurate and detailed resource bid parameters.

PJM should adopt market rules that improve the accuracy of the minimum generation levels and ramp rates submitted by generators for dispatch determinations. In many cases, these submitted generator bid parameters understate the flexibility of the units, such as the use of ramp rate, startup time, or minimum output limits for generator constraints that are not actually physical limits, but rather economic costs associated with more flexible dispatch. Expressing the capabilities and limits of flexible and inflexible supply and demand resources as costs would facilitate more accurate pricing of inflexibility. Bid parameters that understate a unit's actual flexibility contribute to excess payments to inflexible units. PJM needs to know each unit's actual ramp capability to be able to dispatch available resources effectively, but many conventional units' reported ramp parameters are inaccurate. As PJM's MMU explains, "When PJM permits a unit to include inflexible operating parameters in its offer and pays uplift based on those inflexible parameters, there is an incentive for the unit to remain inflexible."[8]

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4 PJM Report to FERC, available at https://www.pjm.com/-/media/documents/ferc/filings/2022/20221018-ad21-10-000.ashx.

5 PJM MMU, PJM State of the Market 2022, Section 4: Energy Uplift, available at https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2022/2022-som-pjm-sec4.pdf.

6 *Id.*

7 For example, see *Ibid*. at 274: "The MMU recommends that PJM clearly identify and classify all reasons for incurring uplift in the day-ahead and the real-time energy markets and the associated uplift charges in order to make all market participants aware of the reasons for these costs and to help ensure a long term solution to the issue of how to allocate the costs of uplift."

8 *Id.*

2. Create a universal participation model.

In its report in FERC's market design docket, PJM discusses its efforts to better reflect the operational characteristics and capabilities of resources including steam, natural gas combined cycle, battery storage, and distributed resources in their commitment and dispatch processes.[9] While such efforts are valuable, PJM should also explore the feasibility of a more elegant and durable solution in which all resource types can express their capabilities through a universal participation model. Under this concept, all resources could describe their capabilities relative to a theoretical perfectly flexible resource.[10] Another long-term approach would be to encourage resources to become closer to perfectly flexible resources by becoming hybrid resources, as discussed in more detail below.[11] This could result in considerable longer-term simplifications to market designs by expecting more of market participants.

3. Give resources the option to control their own commitment and dispatch.

Centralized RTO/ISO spot markets are extremely valuable for aggregating dispersed information from different participants and incentivizing participants to develop more accurate forecasts. To the maximum extent possible, RTO/ISOs should not interfere with market participants' use of their commitment and dispatch preferences to reveal expectations that set efficient prices for all market participants. This includes giving battery storage operators the option of managing their state-of-charge. Some RTO/ISOs have proposed direct RTO/ISO control of storage state-of-charge to address instances of inefficient charging and discharging,[12] though in many cases those problems are symptoms of other market failures discussed below, such as when low price caps cause batteries to discharge earlier than would be optimal. However, there may be value in offering market participants the option of allowing the RTO/ISO to manage their resource for them, as long as they have the right to opt out and manage it themselves.

4. Remove barriers to energy and ancillary services market participation.

Market rules should treat generation resources comparably and allow all generation resources capable of providing a product or service to do so and be fairly compensated. PJM should evaluate its existing ancillary service and ramping product rules to ensure they are non-discriminatory. As noted above, today wind and solar may or may not be the most cost-effective resources to provide certain services given the opportunity cost of curtailing renewable generation. However, as the renewable penetration increases, curtailment will increase, and the opportunity cost of foregone energy production will decline so that

9 For example, see PJM Report to FERC at 28, available at https://www.pjm.com/-/media/documents/ferc/filings/2022/20221018-ad21-10-000.ashx. Also see PJM MMU's 2021 report, available at https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2021/2021-som-pjm-vol2.pdf, at 90: "The MMU recommends that PJM model generators' operating transitions, including soak time for units with a steam turbine, configuration transitions for combined cycles, and peak operating modes."

10 Mark Ahlstrom, "The Universal Market Participation Model" (April 5, 2018), available at: https://www.esig.energy/blog-the-universal-market-participation-model/.

11 Derek Stenclik, Michael Goggin, Erik Ela, and Mark Ahlstrom, "Unlocking the Flexibility of Hybrid Resources" (March 2022), available at: https://www.esig.energy/unlocking-the-flexibility-of-hybrid-resources/.

12 CAISO Department of Market Monitoring (CAISO DMM), Annual Report on Market Issues and Performance (July 27, 2022) at 28, 293, available at: https://www.caiso.com/Documents/2021-Annual-Report-on-Market-Issues-Performance.pdf.

renewables may increasingly become cost-effective sources of ancillary services and flexibility in the upward as well as downward direction.[13] PJM must design its markets and products to allow these services or products to be provided on a non-discriminatory basis by all capable resources.

For example, some ancillary services products have duration requirements that require a resource to be able to sustain providing the service for a longer period of time than necessary, which can prevent variable renewable and duration-limited storage resources from providing those services even though they could efficiently provide them for shorter periods of time. Some energy and ancillary services market rules also prevent renewable and storage resources from switching among providing different services within an hour, even though they can efficiently do so.

PJM's comments in FERC's wholesale market design proceeding reveal an outdated understanding of the reliability services capabilities of renewable and storage resources, which may play a role in its retention of outdated rules that are preventing those resources from providing those services. For example, PJM wrote that "A significant challenge PJM faces over the next five to ten years is the disorderly retirement of resources that provide needed ancillary services. The limitations in how these resources are priced today could well add to the premature and disorderly retirement of these needed resources that are not priced accurately in today's markets."[14]

In reality, batteries, wind,[15] and solar[16] plants all use fast and flexible power electronics that allow them to meet or exceed the ancillary services contributions of conventional generators.[17] FERC now requires new wind, solar, and battery resources to match the reactive power[18] and frequency response[19] capabilities of conventional generators. These power electronics can even use grid power to provide voltage and reactive power support when the plant is not producing power, such as solar plants providing reactive power at night.[20] In contrast, many conventional generators provide little or no flexibility, frequency response, and other needed reliability services.[21]

Curtailed renewables are likely to be a growing source of ancillary services, and the rapid growth of battery and hybrid resources will also likely meet any increase in need for ancillary services. Battery storage and curtailed renewables are excellent sources of frequency

13 Energy + Environmental Economics, Inc., "Investigating the Economic Value of Flexible Solar Power Plant Operation" (Oct. 2018) at 34, available at: https://www.ethree.com/wp-content/uploads/2018/10/Investigating-the-Economic-Value-of-Flexible-Solar-Power-Plant-Operation.pdf.

14 PJM Report at 18, available at https://www.pjm.com/-/media/documents/ferc/filings/2022/20221018-ad21-10-000.ashx.

15 National Renewable Energy Laboratory, "Active Power Controls from Wind Power: Bridging the Gaps" (January 2014), available at: https://www.nrel.gov/docs/fy14osti/60574.pdf.

16 National Renewable Energy Laboratory, "Demonstration of Essential Reliability Services by a 300-MW Solar Photovoltaic Power Plant" (March 2017), available at: https://www.nrel.gov/docs/fy17osti/67799.pdf.

17 Milligan et al, "Alternatives No More: Wind and Solar Power Are Mainstays of a Clean, Reliable, Affordable Grid," IEEE Power and Energy Magazine (Volume: 13, Issue: 6, Nov.-Dec. 2015), available at: https://ieeexplore.ieee.org/document/7299793.

18 Reactive Power Requirements for Non-Synchronous Generation, 155 FERC 61,277 (June 16, 2016), available at: https://www.ferc.gov/sites/default/files/2020-06/RM16-1-000.pdf.

19 Essential Reliability Services and the Evolving Bulk-Power System—Primary Frequency Response, 162 FERC 61,128 (February 15, 2018), available at: https://www.ferc.gov/sites/default/files/2020-06/Order-842.pdf

20 Alice Grundy, "Light Source BP delivers night time reactive power using solar in 'UK First'," Solar Power Portal (November 25, 2019), available at: https://www.solarpowerportal.co.uk/news/lightsource_bp_delivers_night_time_reactive_power_using_solar_in_uk_first.

21 Michael Milligan, "Lightsource of Grid Reliability Services," The Electricity Journal, Volume 31, Issue 9, November 2018, at 1-7, available at: https://www.sciencedirect.com/science/article/pii/S104061901830215X.

response and can even provide fast frequency response that displaces the need for inertia.[22] For example, the 150 megawatt (MW) Hornsdale battery in South Australia has provided fast frequency response to stabilize the grid within seconds of major real-world grid disturbances.[23]

Grid-forming inverters that further expand the reliability services contributions of renewable and battery resources are increasingly being used today. The Dalrymple Substation Battery project in South Australia started commercial operation in December 2018 and has demonstrated that grid-forming batteries can provide short-circuit current contribution, fast frequency response, blackstart, and islanded operation.[24] Batteries have been used to provide blackstart service in multiple islanded microgrids around the world.[25] A recently announced 185 MW battery project in Hawaii will fully replace the grid services currently provided by a nearby retiring coal plant by providing blackstart, fast frequency response, and grid-forming services.[26] Renewable plants can also be designed to provide blackstart and other services. In Great Britain, controls of an existing 69 MW wind farm were modified to be grid-forming, and the wind farm then successfully provided fast frequency response, blackstart, and islanded operation capability.[27]

22 NERC Inverter-Based Resource Performance Task Force, "Fast Frequency Response Concepts and Bulk Power System Reliability Needs" (March 2020), available at: https://www.nerc.com/comm/PC/InverterBased%20Resource%20Performance%20Task%20Force%20IRPT/Fast_Frequency_Response_Concepts_and_BPS_Reliability_Needs_White_Paper.pdf.

23 Giles Parkinson, "'Virtual machine': Hornsdale battery steps in to protect grid after Callide explosion," Renew Economy (May 27, 2021), available at: https://reneweconomy-com-au.cdn.ampproject.org/c/s/reneweconomy.com.au/virtual-machine-hornsdale-battery-steps-in-to-protect-grid-after-callide-explosion/amp/.

24 "A 30MW Grid Forming BESS Boosting Reliability in South Australia and Providing Market Services on the National Electricity Market," in Proc. 18th Int'l Wind Integration Workshop (October 2019), available at https://www.electranet.com.au/wp-content/uploads/2021/01/Wind-Interation-Workshop-30MW-BESS-October-2019.pdf.

25 Oliver Schömann, "Experiences with large grid-forming inverters on various island and Microgrid projects," Hybrid Power Systems Workshop (May 2019), available at: https://hybridpowersystems.org/wp-content/uploads/sites/13/2019/06/3A_3_HYB19_017_presentation_Schoemann_Oliver_web.pdf.

26 Julian Spector, "Hawaii building huge new battery, bidding farewell to coal," Canary Media (August 18, 2021), available at: https://www.canarymedia.com/articles/hawaii-building-huge-new-battery-bidding-farewell-to-coal/.

27 A. Roscoe, et. al., "Practical experience of providing enhanced grid forming services from an onshore wind park," in Proc. 19th Wind Integr. Workshop (November 2020).

5. Price resources' inflexibility.

Allow more resources to include fixed costs in their bids. Currently, FERC allows only fast-start resources to include start-up and no-load costs in their bids. Some experts argue that rules around price formation need to evolve so that resource types other than fast-start resources can include start-up and other fixed costs in their bids, as this will incorporate the cost of meeting reliability needs in energy market prices instead of recovering them through out-of-market payments.[28]

At present, energy market prices and dispatch do not perfectly incorporate the fact that most conventional generators have "non-convex" costs, which are essentially fixed costs that occur at various points on the resource's output curve and are notably higher at unit startup and lower output levels. While these costs are accounted for in unit commitment decisions, there is active RTO/ISO stakeholder debate about whether these costs should be reflected in energy market prices or be allocated as uplift costs outside the market-clearing Locational Marginal Price (LMP) calculation. This debate has focused on which convex costs should be incorporated into price (start-up and no-load costs, or other fixed costs as well), and for which units (quick-start units, only on-line resources, etc.).

In 2017, PJM proposed to allow a range of fixed costs to be included in the market-clearing price that would be set by many inflexible units.[29] This would have allowed on-line coal and nuclear plants to set prices well above their true marginal cost of producing electricity. This proposed form of Extended LMP would inefficiently support generators that are not providing flexibility, imposing an unjust and unreasonable cost burden because it charges customers a premium without delivering any reliability benefits, while insulating inflexible conventional plants from the cost of their inflexibility. This proposal is inconsistent with the PJM MMU recommendation "that PJM not pay uplift to units not following dispatch."[30] However, alternative formulations that only reward resources offering flexibility can be efficient.

While most types of flexible duration-limited resources do not have start-up and no-load costs and therefore, their bids would not be directly affected, other resources' inclusion of those costs in their bids would increase market clearing prices and thus infra-marginal revenues for resources that do not have those costs. To avoid perversely subsidizing inflexible resources, those costs should not be recoverable through make-whole or other out-of-market payments to those resources but should be included in prices to provide accurate short- and long-run incentives to all resources.

Do not reward resources for their inflexibility. Today RTO market mechanisms routinely provide out-of-market uplift payments to committed generators that cover costs associated with their inflexibility. The PJM MMU has proposed a number of market reforms to appropriately price the inflexibility cost of resources and ensure they are not rewarded

28 P. Gribik et al., "Extended Locational Marginal Pricing (Convex Hull Pricing)" (June 2, 2010), available at: https://cms.ferc.gov/sites/default/files/2020-05/20100530130229-Gribik%2C%2520Zhang%2C%2520Midwest%2520ISO%2520-%2520Extended%2520LMP.pdf.

29 PJM Interconnection, LLC, "Proposed Enhancements to Energy Price Formation" (November 15, 2017), available at: https://pjm.com/-/media/library/reports-notices/special-reports/20171115-proposed-enhancements-to-energy-price-formation.ashx.

30 PJM MMU 2022 report, at 273.

for their inflexibility.[31] Without weighing in on each of the proposed reforms, we generally support the intent of reducing out-of-market subsidies for inflexibility and instead directly accounting for these costs in commitment and dispatch processes.

More to the point—market participants today have a variety of technologies at their disposal to meet the needs of the power system, including flexibility. PJM should consider ending the use of uplift payments and other out-of-market payments if a generator could meet the required availability and performance with the use of a better or different technology. For example, generators that are not able to ramp down and up quickly enough to meet the needs of the grid could instead use fast-ramping technologies like battery storage in combination with existing resources to cover that liability, rather than impose that cost on load. PJM's MMU recommends that uplift be paid only based on operating parameters that reflect the flexibility of the benchmark new entrant unit.[32] While that benchmark is currently a natural gas combined cycle generator, given battery storage's increasing share of new capacity additions, its superior flexibility, and ability to be deployed modularly at existing generators, battery storage could set that benchmark going forward.

B. Establish more efficient unit commitment processes

Unit commitment is the process by which generators are selected to operate ahead of the real-time market, which is primarily achieved through the day-ahead market. Because the vast majority of energy is transacted in the day-ahead market and inefficient commitment imposes costs on consumers while distorting price signals, there is considerable benefit to improving the efficiency of the commitment process.

1. Increase the use of probabilistic unit commitment.

Probabilistic unit commitment refers to processes that directly incorporate information about uncertainty in electricity supply and demand forecasts into unit commitment decisions. Today, operators make conservative unit commitment and dispatch decisions in part because they recognize that their deterministic methods and forecasts are not fully accounting for uncertainty and risk.[33] Using more rigorous quantitative methods to account for that risk would produce more efficient, lower-risk operations.

For example, commercially available renewable output and electricity demand forecasts typically include detailed information about the uncertainty of those forecasts, but it is common for only the median (p50) value to be used as the deterministic input for committing and dispatching other resources. Most forecast vendors can quantify the uncertainties around a production forecast, such as uncertainty about the magnitude of a weather event (e.g., the distribution of temperature, irradiance or wind speed outcomes)

31 See certain recommendations in the 2021 State of the Market Report for PJM, Monitoring Analytics, LLC, Section 4: Uplift, available at: https://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2021/2021-som-pjm-sec2.pdf.

32 MMU 2022 report, at 273.

33 Even with these conservative assumptions, RTOs/ISOs may not always accurately predict tail-end events, such as PJM's inability to accurately forecast both load and available reserves during Winter Storm Elliott. See: https://pjm.com/-/media/committees-groups/committees/mic/2023/20230111/item-0x---winter-storm-elliott-overview.ashx.

and the timing of an event (e.g., when a front resulting in abrupt temperature, wind speed, or cloud cover changes will arrive). Probabilistic unit commitment tools that incorporate such uncertainties would yield more efficient commitment of resources based on risk-managed inter-temporal solutions, especially considering that many of the uncertainties have correlated impacts on both supply and demand. For example, if forecasts indicate a significant chance of both very high load and very low renewable output, operators will likely want to commit more resources. However, because those risks are not reflected in the median value for either forecast, current deterministic methods do not automatically incorporate them into commitment decisions, forcing operators to attempt to subjectively incorporate them.

While human operators have many advantages relative to computers due to their deep knowledge of the system developed over years of experience, operators can benefit from greater use of decision support tools that identify statistical patterns and use probabilistic methods to make better, lower-risk commitment and dispatch decisions. Moreover, the use of subjective judgement can be time-consuming during critical events. The use of such tools would minimize inefficient dispatch and uplift costs and reduce generation overcommitment. Many resource owners and power traders use probabilistic methods to make decisions about the dispatch of energy-limited resources like energy storage, and therefore PJM operators would also benefit from the use of those tools.

We encourage PJM to quickly move towards incorporating probabilistic tools into unit commitment. Directly incorporating probabilistic analysis into unit commitment greatly exceeds the capabilities of human operators to automatically synthesize different types of risk (e.g., magnitude vs timing) as well as correlations among load and the output of different types of generators across a lengthy historical record, and optimally mitigate that risk.

2. Decrease the lead time for unit commitment.

Because forecast error for electricity supply and demand significantly decreases as one reduces the forecast horizon,[34] there is a significant benefit in making or updating unit commitment decisions as close to real-time as possible. As discussed below, one solution for achieving this is eliminating out-of-market payments that perversely reward or at least hold harmless resources that are inflexible or otherwise require lengthy lead times to start up, procure fuel, or undertake other processes. Grid operators can also use multi-interval or rolling unit commitment processes to schedule as many resources as close to real-time as possible.

Some RTO/ISOs attempt to use multi-interval commitment processes today, though there is significant room for improvement in these processes.[35] Using probabilistic tools to increase the accuracy and value of demand and supply forecasts will not only yield value in the day-ahead market, but also in shorter-term unit commitment processes.

34 For example, see the increase in wind forecast error at greater time horizons in R. Widiss and K. Porter, “A Review of Variable Generation Forecasting in the West July 2013 — March 2014” (March 2014) at 4, available at: https://www.nrel.gov/docs/fy14osti/61035.pdf.

35 B. Neuven et al, “Stochastic Look-Ahead Commitment: A Case Study in MISO,” 2021, available at https://optimization-online.org/wp-content/uploads/2021/10/8660.pdf.

C. Evaluate new market products

Another solution to minimize out-of-market actions and to better use the new resources interconnecting to the grid is to create new ancillary service or other market products for needed services. In their filings in FERC's wholesale market design docket, many grid operators expressed an interest in new flexibility market products to address variability and uncertainty in electricity supply and demand. The design of any new products must adhere to the other two principles delineated in this section, and the creation and design of such products must be balanced with accurately pricing the needed services, and a recognition of the growth of storage and hybrid resources and optimal price signals for those technologies. For example, storage requires real-time price signals that it can respond to quickly along with a longer-term horizon for determining optimal charging and discharging.[36] Ongoing large-scale additions of highly flexible battery storage and hybrid resources, combined with effective energy market price formation, may obviate the need for the new ramping products discussed in PJM's filing in the FERC market design proceeding. Battery and hybrid resources will provide the needed flexibility simply by following the incentives for charging and discharging in real-time market prices. It is important that new market products aimed at flexibility not suppress those price signals. Similarly, it is important that price caps not interfere with optimal dispatch.

Market operators have tried several different approaches to procuring flexibility through ramping products, with varying success,[37] and some are also considering the creation of similar uncertainty products that reserve flexibility to address uncertainty in day-ahead and multi-day forecasts for electricity supply and demand. Using a market to procure flexible capacity to address uncertainty is more efficient than the status quo approach of over-committing resources without regard to their flexibility, which can perversely incentivize inflexible resources. To that end, PJM and other RTO/ISOs should structure such uncertainty products so their pricing and selection of resources efficiently reflects the ability of a resource to cost-effectively provide flexibility. As discussed below, make-whole payments can perversely reward resources for their inflexibility. RTO/ISOs should also allow duration-limited resources, like battery storage and curtailed variable renewables, to provide this uncertainty product. Renewable resources are unlikely to be the most economic sources of flexibility during most intervals today, but at higher renewable penetrations curtailed renewable resources will be a primary source of flexibility.

36 See for example, CAISO's statement in its report in FERC's wholesale market design docket that a longer-term ramp product could "support optimizing the state of charge of energy storage over a longer time horizon than the current real-time market multi-interval optimization." CAISO Report to FERC, available at https://elibrary.ferc.gov/eLibrary/filedownload?fileid=B6CEB7B6-5A3D-C669-9348-83ECC4800000, at 28-29.

37 For example, the California Independent System Operator (CAISO) has used the Flexible Resource Adequacy Criteria and Must Offer Obligations (FRACMOO) program to procure flexibility. CAISO redesigned this service after it was widely viewed to have failed to efficiently incentivize the provision of flexibility, with CAISO itself noting the previous version "risks exacerbating the ISO's operational challenges by sustaining largely inflexible resources," from CAISO, "Flexible Resource Adequacy Criteria and Must Offer Obligation – Phase 2" (January 31, 2018) at 3, available at: https://www.caiso.com/Documents/RevisedDraftFlexibleCapacityFrameworkProposal-FlexibleResourceAdequacyCriteria-MustOfferObligationPhase2.pdf. There are still significant concerns about the efficiency of the current flexible ramping product. As the CAISO Division of Market Monitoring (DMM) notes:

"Although the CAISO has implemented numerous improvements to this product since its introduction in 2016, CAISO operators continue to rely primarily on significant manual interventions to ensure sufficient ramping capacity is available during the peak ramping hours. These manual interventions include significant upward biasing of the load forecast used in the residual unit commitment and hour-ahead scheduling processes as well as manual commitments and upward dispatches of gas-fired generating units. These manual interventions have remained high, or even increased, since introduction of the flexible ramping product." CAISO Department of Market Monitoring (CAISO DMM), Annual Report on Market Issues and Performance (July 27, 2022) at 21, available at: https://www.caiso.com/Documents/2021-Annual-Report-on-Market-Issues-Performance.pdf.

Another potential solution to concerns about increasing uncertainty at higher penetrations of variable resources is to make spinning and non-spinning contingency reserves available for unexpected renewable drop off events. Today contingency reserves are used to restore system supply and demand following the loss of a large conventional generator, typically with a mix of fast-acting spinning resources (faster than 10-minute response) and slower-responding non-spinning resources (less than 30-minute response). The cost of these reserves is currently socialized to load rather than assigned to generators, even though the need for these reserves is driven by large conventional generator failures and these reserves are not activated for abrupt drops in renewable output or load forecast errors. While renewable output generally changes gradually and predictably, at high penetrations a large, unexpected drop-off in wind or solar output over a fraction of an hour can occur several times per year. Outside of RTO/ISO footprints, grid operators like Public Service Company of Colorado have obtained FERC approval to hold non-spinning operating reserves for large and unexpected drops in renewable output, and the type and performance of resources that provide those reserves is identical to the non-spinning reserves that are used for conventional generator contingencies and load forecast shortfalls. Because conventional generator failures and sudden renewable output drops have similar impacts on short-run grid operations for reliability, drawing from a common set of reserves may be more efficient than holding separate reserves for each type of event.

Some grid operators have expressed interest in creating market products for inertia or fast frequency response. While the Eastern and Western Interconnections have abundant inertia today, which would likely result in market prices being zero for the foreseeable future, the growth of asynchronous renewable and battery storage resources is likely to eventually make such markets valuable. Renewable and storage resources can offset the need for inertia by providing fast frequency response, which is orders of magnitude faster than the typical primary frequency response of conventional generators to a grid frequency disturbance. Fast frequency response can displace much of the need for inertia by stabilizing frequency in the initial seconds following the loss of a large generator (inertia is instantaneous and determines the rate of change of frequency after a disturbance, while fast frequency response provides additional supply and is therefore not a complete substitute for inertia). NERC has recommended allowing renewable and hybrid resources to exceed a transmission line's emergency operating limit to provide fast frequency response, as this response is only needed for a short period of time and so would not risk damage to the transmission system. That would potentially create a large opportunity for battery storage, curtailed renewables, or hybrid resources with excess capacity behind the point of interconnection to provide significant amounts of fast frequency response service at low cost.[38]

PJM should work with FERC, NERC, Reliability Coordinators, transmission service providers, and others to: (1) examine the feasibility of removing impediments to a resource temporarily exceeding its injection limit to provide fast frequency response in the pro forma interconnection agreements, NERC Standards, and PJM operating practices and rules; and (2) determine the best design for a frequency response market, including learning from ERCOT's experience with implementing a fast frequency response market.[39] As noted above, fast frequency response service also allows the grid to operate reliably with less inertia, so such a market can help postpone the need for an inertia market and reduce headroom requirements for the rest of the generation fleet.

II. INCREASE THE ENERGY MARKET BID CAP TO BETTER REFLECT VALUE OF LOST LOAD

PJM's energy market has a relatively low price cap of $3,700/MWh,[40] which can mute the incentive for performance during periods of extreme scarcity and result in under-investment in flexible generation that contributes to resource adequacy. In general, real-time energy market prices provide a much stronger incentive for resource performance than capacity market requirements, which often do not reflect the timing of need.

Low price caps can also cause unintended consequences in energy markets. For example, energy market price caps in CAISO caused many storage resources to prematurely discharge during early afternoon periods in the September 2022 heat wave, because once prices hit the $2,000/MWh cap storage resources had no incentive to retain their state of charge even though it was known that net load would be even higher later in the afternoon and evening.[41] Similarly, different price caps between RTO/ISOs or between RTOs/ISOs and non-RTO areas can cause inefficient transactions during periods of widespread scarcity. Such an inefficiency itself can result in unjust and unreasonable transactions, which the price caps were initially intended to prevent.

> **The PJM market monitor has proposed reforms to better price scarcity:**
>
> The MMU recommends that PJM stop capping the system marginal price in RT SCED and instead limit the sum of violated reserve constraint shadow prices used in LPC to $1,700 per MWh…The MMU recommends, if PJM implements extended downward sloping ORDCs, that PJM calculate the probability of reserves falling below the minimum reserve requirement

38 NERC, "Utilizing the Excess Capability of BPS-Connected Inverter-Based Resources for Frequency Support" (September 2021) at 1-2; available at: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/White_Paper_IBR_Hybrid_Plant_Frequency_Response.pdf.

39 ERCOT, "Implementation Details for Fast-Frequency Response (FFR) Advancement Project" (July 25, 2022), available at: https://www.ercot.com/calendar/event?id=1658240344448.

40 FERC Order in docket EL19-58-008, February 2022, available at https://www.pjm.com/-/media/documents/ferc/orders/2022/20220211-el19-58-008.ashx.

41 The Public Advocates Office, "Preliminary Analysis of California's Resiliency During the September 2022 Heat Wave" at 8, available at: https://www.publicadvocates.cpuc.ca.gov/-/media/cal-advocates-website/files/reports/220922-caladvocates-sept-22-heat-wave-analysis---full.pdf.

(MRR) based on ten minute rather than 30 minute forecast error, and on forced outages in the ten minute rather than the 30 minute look ahead window to model the uncertainty in the inputs to RT SCED.[42]

It is important to note that load-serving entities and their consumers can and do use long-term contracts and other hedging mechanisms to avoid incurring extremely high energy market prices, particularly in wholesale markets with high price caps like ERCOT. The vast majority of energy is procured through those bilateral contracts, with most generators and load-serving entities only using the energy market to address marginal deviations in supply or demand. While retail electricity markets are regulated by states, retail markets play an important role in resource adequacy by ensuring that load-serving entities can and are incentivized to use contracts to hedge price risk and are not "free riding" on the power system's resource adequacy.[43]

FERC and PJM should work with the states to ensure value-based pricing along with hedging to protect consumers from high and volatile prices, and clarify that economic hedging is a state responsibility. States can elect to have the RTO/ISO enforce reserve requirements but recognize that it was never the purpose of RTO/ISOs to procure long term energy or manage price risk for consumers. States can and should ensure their retail structures enable and facilitate long-term contracting or other mechanisms to protect retail customers from high and volatile prices and to procure the types of power the state and state load serving entities and their customers wish to utilize. Some states have retail competition and allow more sophisticated customers to procure their own power, while some do not, and there are wide varieties of arrangements even within RTOs/ISOs. PJM and FERC should ensure that wholesale spot prices at all times and locations reflect the full value of reliability, while states work with their retail structures to ensure appropriate hedging.

III. IMPROVE TRANSPARENCY AND EFFICIENCY BY USING OTHER MECHANISMS TO COUNTER MARKET POWER

Market power mitigation rules that come into effect if resources fail the three pivotal supplier test generally limit resources' bids to their marginal operating costs (heat rate multiplied by fuel cost plus variable O&M costs for a typical fossil fuel plant). That method, while justified for conventional resources to achieve competitive prices where true supply and demand intersect, does not apply well to storage or demand resources, for which the marginal cost of production is based on a temporal opportunity cost rather than the cost of fuel. The opportunity cost of storage fluctuates widely over time and is not known to market monitors because it is based on expectations of future prices and dispatch. Therefore, storage and demand resources should not be subject to such operating cost-based bid caps.

42 PJM MMU (2021) at 84.

43 See Wind Solar Alliance, "Who's the Buyer? Retail Electric Market Structure Reforms in Support of Resource Adequacy and Clean Energy Deployment" (March 2020), available at: https://gridprogress.files.wordpress.com/2020/03/whos-the-buyer.pdf.

Another potential improvement for the Commission and PJM to consider is to make planned generator and transmission outages transparent so they are priced in the market, rather than keeping them confidential to prevent the exercise of market power as is standard under PJM operating practice today. PJM, its market monitor, and FERC can instead use existing monitoring and regulatory oversight mechanisms (including market monitor review of conventional generator bids to ensure they reflect true marginal cost when markets fail pivotal supplier tests) to prevent a resource owner from exercising market power by withholding output when other generators or transmission lines are on outage. This would allow more efficient commitment and dispatch of resources and market transactions in advance of and during those outages.

Another valuable reform is for RTOs to play a greater role in coordinating transmission and generation outages to reduce congestion costs. The PJM IMM has recommended greater coordination of outages by PJM, including requiring more timely rescheduling of outages: "The MMU recommends that PJM increase the coordination of outage and operational restrictions data submitted by market participants via eDART/eGADs and offer data submitted via Markets Gateway… The MMU recommends that PJM reevaluate all transmission outage tickets as on time or late as if they were new requests when an outage is rescheduled, and apply the standard rules for late submissions to any such outages."[44]

IV. IMPROVE TRANSMISSION UTILIZATION WITHIN PJM AND AT ITS SEAMS

In its report in FERC's wholesale market design docket, PJM downplays the importance of transmission for enabling the resource transition.[45] While transmission expansion is outside of the scope of this report, we would refer to comments submitted by ACORE on the importance of proactive multi-value transmission planning with broad regional cost allocation in FERC's NOPRs on Transmission Planning and Cost Allocation and Generator Interconnection.[46] However, many aspects of how the existing transmission system is used in PJM are related to market design, including seams issues at PJM's borders, accounting for congestion within PJM, and using ambient ratings and grid-enhancing technologies to reduce congestion.

A. Fix seams between PJM and neighboring grid operators

PJM's MMU proposes an ambitious solution for optimizing transactions across PJM's seams with neighboring grid operators: "The MMU recommends that PJM explore an interchange optimization solution with its neighboring balancing authorities that would remove the need for market participants to schedule physical transactions across seams. Such a solution would include an optimized, but limited, joint dispatch approach that uses supply curves and treats seams between balancing authorities as constraints, similar to other constraints within an

44 PJM MMU (2021) at 103.

45 PJM report at 12.

46 Available at: https://acore.org/wp-content/uploads/2022/08/ACORE-Comments-on-FERCs-Transmission-Planning-NOPR.pdf.

LMP market."[47] Such an optimization between market and non-market entities would be a highly efficient way to increase seams coordination and might serve as a model for seams management in other regions.

In addition, the PJM market monitor recommends more incremental reforms, like "that PJM permit unlimited spot market imports as well as unlimited nonfirm point to point willing to pay congestion imports and exports at all PJM interfaces in order to improve the efficiency of the market."[48] It also recommends that for import transactions, "the submission deadline for real-time dispatchable transactions be modified from 1800 on the day prior, to three hours prior to the requested start time, and that the minimum duration be modified from one hour to 15 minutes. These changes would give PJM a more flexible product that could be used to meet load in the most economic manner."[49]

B. Price congestion more efficiently

Transmission congestion within PJM has been increasing.[50] While the ultimate solution is building more transmission, market reforms can more efficiently account for congestion. PJM's MMU discusses a variety of concerns related to how PJM's pricing logic allows inflexible resources to set LMP.[51]

47 PJM MMU (2021) at 99.
48 *Id.*
49 *Id.*
50 PJM MMU (2021) at 564.
51 PJM MMU (2021) at 566-568.

C. Use ambient ratings and Grid-Enhancing Technologies

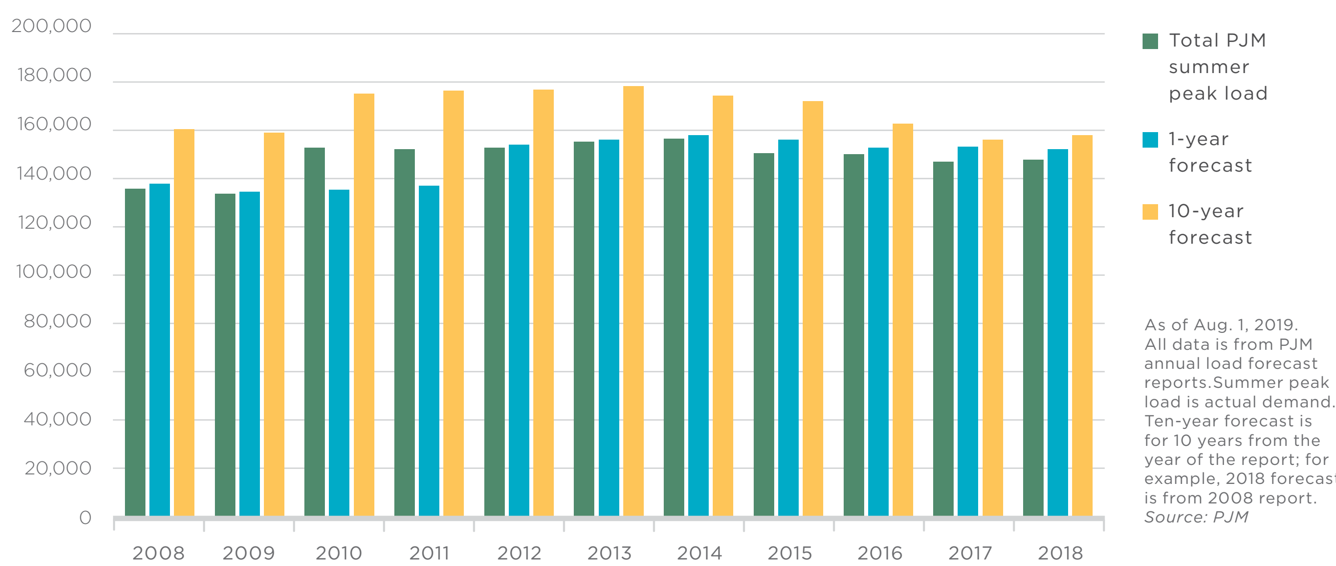
PJM's market monitor strongly recommends more efficient practices for rating transmission lines, including the use of ambient ratings and Grid-Enhancing Technologies. The PJM MMU "recommends that all PJM transmission owners use the same methods to define line ratings and that all PJM transmission owners implement dynamic line ratings (DLR), subject to NERC standards and guidelines, subject to review by NERC, PJM and the MMU, and approval by FERC,"52 and that "PJM routinely review all transmission facility ratings and any changes to those ratings to ensure that the normal, emergency and load dump ratings used in modeling the transmission system are accurate and reflect standard ratings practice."[53]

V. IMPROVE ENERGY MARKET PRICE SIGNALS BY REDUCING OVER-PROCUREMENT OF CAPACITY

Capacity market rules and their resulting procurement have a large impact on energy market prices and functioning. In particular, the history of capacity market over-procurement has harmed energy market price formation and depressed incentives for real-time performance and flexibility.

For example, PJM's capacity market has resulted in over-procurement due to overestimates of load growth, as shown below, and other factors that inflate capacity market prices, including unduly conservative assumptions about the availability of imports during peak demand periods and an assumed net Cost of New Entry (CONE) that is too high because the calculated energy and ancillary services revenue offset is too low.

FIGURE 1. *PJM load, forecast vs. actual, 2008-2018 (MW)*



As of Aug. 1, 2019. All data is from PJM annual load forecast reports.Summer peak load is actual demand. Ten-year forecast is for 10 years from the year of the report; for example, 2018 forecast is from 2008 report. *Source: PJM*

52 PJM MMU (2021) at 103.
53 *Id.* at 89.

FERC can significantly improve the accuracy of the net CONE calculation by allowing the use of a forward-looking instead of backward-looking energy and ancillary services revenue offset,[54] as endorsed by the PJM MMU.[55] Other improvements to the net CONE calculation include more accurately accounting for how new gas generators tend to be optimally located in areas that minimize pipeline expansion costs and also offer a lower delivered cost of gas supply, increasing their profits from providing energy and ancillary services. Finally, the shape of the Variable Resource Requirement curve should be based on the Marginal Reliability Impact of additional capacity.[56]

PJM can also better account for the availability of imports to meet resource adequacy needs. PJM assumes imports provide 2,127 MW of reduced installed capacity need.[57] Imports during PJM's highest load hours are often around 5,000 MW, and in the range of 6,000-7,000 MW when PJM electricity prices are also higher than $180/MWh.[58] Imports during some high demand hours have been as high as 10,000 MW. PJM could realize significant consumer savings with more accurate assumptions for the availability of imports during peak periods. PJM should also explore ways to credit capacity value to new interregional transmission lines that reduce the need for peak capacity by accessing diversity in electricity demand and supply with neighboring grid operators. Accessing and accounting for geographic diversity will become increasingly important at higher renewable penetrations, given geographic diversity in wind and solar output patterns.

Correcting those assumptions will counter a historical pattern of over-procurement in capacity markets. Not only does capacity market over-procurement impose billions of dollars in excess cost on consumers, it also distorts the energy market in ways that harm price formation and the ability of markets to attract more flexible resources. Over-procuring capacity shifts revenue from the energy market to the capacity market and suppresses energy market prices during periods of scarcity. This revenue shift reduces the earnings of renewable resources, which earn most of their revenue in the energy market and suppresses the energy market price signal for all resources, particularly flexible resources like battery storage, to perform during periods of scarcity.[59]

The reduced incentive for flexible resources and impediment to the transition to cleaner resources is compounded by the fact that PJM's capacity market only procures capacity, and not flexible capacity. Flexible capacity from batteries and other resources is increasingly more valuable than inflexible capacity as the penetration of variable renewable resources increases, yet capacity markets do not distinguish between flexible and inflexible capacity.[60] Capacity markets also do not inherently incentivize the performance of resources during periods of

54 Brattle Group, "PJM CONE 2026/2027 Report" (April 21, 2022) at vii-viii, available at: https://www.pjm.com/-/media/library/reports-notices/special-reports/2022/20220422-brattle-final-cone-report.ashx.

55 PJM MMU (2021) at 98.

56 The Brattle Group, Fifth Review of PJM's Variable Resource Requirement Curve (April 19, 2022) at 25-26, available at: https://www.pjm.com/-/media/committees-groups/committees/mic/2022/20220422-special/brattle-pjm-fifth-vrr-curve-study-2026-27---final.ashx.

57 PJM, "2021 PJM Reserve Requirement Study – 11-year Planning Horizon: June 2021 – May 2032," (Oct. 5, 2021) at 34; available at: https://www.pjm.com/-/media/committees-groups/committees/pc/2021/20211005/20211005-item-05b-2021-pjm-reserve-requirement-study.ashx.

58 Energy Information Administration, Form EIA-930; available at https://www.eia.gov/electricity/gridmonitor/knownissues/xls/PJM.xlsx; https://dataminer2.pjm.com/feed/rt_hrl_lmps.

59 Grid Strategies, "Too Much of the Wrong Thing: The Need for Capacity Market Replacement or Reform" (November 2019) at 8-9, 12, available at: https://gridprogress.files.wordpress.com/2019/11/too-much-of-the-wrong-thing-the-need-for-capacity-market-replacement-or-reform.pdf.

60 Energy Systems Integration Group, "Beyond Capacity Adequacy" (September 5, 2018), available at: https://www.esig.energy/beyond-capacity-adequacy/.

scarcity, although PJM has reformed its capacity market to better incentivize performance, resulting in large penalties for resources that failed to perform funding payments to resources that overperformed during Winter Storm Elliott. However, energy markets are still the optimal means for incentivizing performance and flexibility during periods when those services are most needed.

To address these concerns, PJM's MMU has recently recommended that capacity resources be required to offer flexibility: "The MMU recommends, in order to ensure effective market power mitigation and to ensure that capacity resources meet their obligations to be flexible, that capacity resources be required to use flexible parameters in all offers at all times."[61]

The PJM MMU has also noted that current capacity market rules often pay resources even if they fail to perform, which distorts market outcomes: "The MMU recommends that resources not be paid the daily capacity payment when unable to operate to their unit specific parameter limits." For gas generators, "The MMU recommends that PJM not approve temporary exceptions that are based on pipeline tariff terms that are not routinely enforced, and based on inferior transportation service procured by the generator."[62]

The PJM market monitor has also recommended reforms to minimize out-of-market reliability must run (RMR) payments: "The MMU recommends that RMR units recover only the incremental costs, including incremental investment costs, required by the RMR service that the unit owner would not have incurred if the unit owner had deactivated its unit as it proposed. Customers should bear no responsibility for paying previously incurred costs, including a return on or of prior investments."[63]

Another important step to ensure capacity markets properly credit resources' contributions to resource adequacy is to account for correlated outages of all types of generators, including thermal generators. During extreme heat, cold, or widespread disruptions to fuel supply or cooling water, many conventional generators experience forced outages or derates at the same time. Correlated outages, including widespread loss of gas generators due to fuel supply interruptions, occurred in multiple regions during the 2014 and 2019 Polar Vortex events, the 2018 Bomb Cyclone, Winter Storm Uri in 2021, and Winter Storm Elliott in 2022. Astrapé Consulting found that in part of PJM, these outages can reduce the capacity value of conventional generators to around 85% in summer and 82% in winter, and as low as 76% if gas generator fuel supply interruptions are accounted for in winter.[64] However, the impact of correlated outages on conventional generators' capacity value is not fully accounted for in any RTO/ISO's method of capacity accreditation. NERC data indicate that correlated outages of thermal generators occur in all ISO/RTO markets.[65] In addition to understating the resource adequacy risk posed by correlated outages from conventional generators, the inappropriate accreditation biases markets towards conventional generators and away from renewable and

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61 PJM IMM (2021) at 84.

62 *Id.* at 89.

63 *Id.* at 95.

64 Astrapé Consulting, "Accrediting Resource Adequacy Value to Thermal Generation" (March 30, 2022), available at: https://info.aee.net/hubfs/Accrediting%20Resource%20Adequacy%20Value%20to%20Thermal%20Generation-1.pdf.

65 Murphy et al., "Resource adequacy risks to the bulk power system in North America," Applied Energy, Volume 212, 15 February 2018, Pages 1360-1376, available at: https://www.sciencedirect.com/science/article/pii/S0306261917318202.

storage resources, whose correlations in their output patterns are accounted for by current methods, such as the Effective Load Carrying Capability (ELCC) methodology PJM uses to assign capacity value to renewables and storage.

PJM should include all resources in a single capacity accreditation method instead of applying separate methods to thermal generation and to renewables and storage resources. Methods should account for correlated outages and derates of conventional generators, including gas supply and transportation interruptions and shortfalls. For example, instead of using the reserve margin to cover unexpected failures of generating units, many experts now believe it is more efficient to reduce the reliability contributions accredited to resources that experience widespread correlated failures. As Astrapé explained in its recent report:

> "Overall, directly evaluating resource uncertainty on the supply-side delivers a more accurate accreditation of the reliability contributions from each resource type. Today, a portion of the thermal resource uncertainty is not being directly accounted for in its capacity accreditation, and therefore that uncertainty is being socialized to load. Accounting for the uncertainty categories in this report creates a more consistent approach for determining capacity accreditation between resources currently assessed via ELCC (wind, solar, storage) and thermal resources."

Capacity accreditation methods like ELCC should also account for changes in resource accreditations due to correlations across all resources in the portfolio, instead of looking at correlation within each resource type alone--i.e., just using a declining curve based on the penetration for each resource.[66] In particular, wind, solar, and storage resources have a large synergistic benefit that is often ignored in capacity market accreditation. Using a declining curve for each resource without accounting for offsetting synergistic benefits among resources can significantly understate the capacity value of those resources and bias resource selection against resources that add positive interactions with other resources.

66 Energy + Environmental Economics, "ELCC Concepts and Considerations for Implementation," Presentation to the NYISO Installed Capacity Working Group (August 30, 2021) at 29-35, https://www.nyiso.com/documents/20142/24172725/NYISO%20ELCC_210820_August%2030%20Presentation.pdf.

Capacity accreditation methods should also properly model the output patterns of the future renewable fleet. If the future fleet is modeled by scaling up historical renewable output profiles, benefits from expected performance improvements from technology advances and geographic diversity in the future renewable fleet should be accounted for. Scaling methods that miss geographic diversity benefits, such as the common error of linearly scaling the output of existing resources, should be avoided.[67] In general, using synthetic output profiles to model the addition of future resources avoids the errors from attempting to scale historical output profiles.

VI. CONCLUSION

The above recommendations seek to maximize the use of markets, recognizing that well-designed markets are the most efficient way to aggregate dispersed information and translate it into a price signal for performance that reflects the value of reliability. PJM should continue to use technology-neutral market design that defines reliability needs and allows any resource capable of providing a needed service to offer to do so. This will create a level playing field in the market and enable a reliable and efficient transition to new resources by unleashing their capabilities. We encourage states and other stakeholders to work with PJM to implement these reforms.

67 National Renewable Energy Laboratory, "Cost-Causation and Integration Cost Analysis for Variable Generation" (June 2011) at 27-29, available at: https://www.nrel.gov/docs/fy11osti/51860.pdf.