

September 16 Co-Located Load Order Workshop Stakeholder Feedback Poll: Question 1

Company Name	Based on the information presented at the September 16 Co-Located Load Order Workshop, what feedback would you like to provide to PJM?
American Clean Power Association	Queue reform is still at risk, and the September 16 detail sharpens rather than resolves the concern. PJM's 2022 cluster-study reforms succeeded because clusters were built around a relatively homogeneous population — generation projects on defined cycles, with cost allocation calibrated to that population. Folding large load into the same Screening Window and Decision Point structure reintroduces exactly the heterogeneity those reforms eliminated. The September 16 presentation's Turn 1/Turn 2 mechanics — a load's forecast revision or withdrawal triggering a cluster re-run before Turn 2 — is a concrete illustration of the restudy-cascade risk ACP flagged in August, not a mitigation of it. PJM should show how a large load's change in status is prevented from delaying the generators studied alongside it. The structural shift out of the Supplemental Project framework remains broader than the Order requires. The Show Cause Order ties joint study of load and generation to electrical proximity and enforceable output limits. PJM's proposal applies the new cluster process — and its escalating financial deposits — to all named large load, not just the proximate, output-limited pairs the Order addresses. ACP continues to ask PJM to explain why the full scope of this shift, including its removal of large-load-driven upgrades from Attachment M-3 zonal cost recovery, is necessary to satisfy the Order. Cost allocation uncertainty is now quantified, and that makes it more urgent, not less. The September 16 presentation gave the first concrete numbers: a Decision Point 1 deposit of \$5,000/MW plus 35% of the reliability cost estimate (capped at \$25,000/MW), and a Decision Point 2 deposit of \$8,000/MW plus 100% of both reliability and interconnection cost. Using PJM's own \$20,000/MW illustrative reliability estimate, that's roughly \$1.2 million at risk by DP1 and \$4.1 million by DP2 for a 100 MW resource — real money attached to a cost allocation question ACP has not seen resolved. PJM should state clearly, before these deposit obligations attach, whether a backbone or network upgrade jointly identified through a cluster study retains RTEP/Schedule 12 treatment or shifts to the generation interconnection customers in the cluster. Financial milestones are now proposed on a specific, binding clock, tied to modeling and computing capability that is still unproven. ACP supports PJM's goal of giving interconnection customers faster cost information so they can decide whether to remain in the queue. But the September 16 proposal attaches real, escalating deposits — not just information — to a 16-week Screening Window built around that capability. If the tools underperform, the financial exposure lands on the generator, not PJM. ACP recommends PJM pilot and demonstrate the modeling and computing capability's performance before attaching binding financial milestones to it. A November filing remains premature for a proposal of this scope and specificity. The September 16 presentation resolved some open questions (the deposit formula, the Application Gate requirements) but left others open — including the Decision Point 3 true-up test, where PJM's own materials still show unfilled "XXX%" thresholds. A structural, multi-year proposal that touches RTEP cost allocation, introduces new binding financial milestones, and still has unset thresholds in its own true-up mechanism needs a timeline that matches its complexity, not a November filing. One additional, specific concern raised by the September 16 Application Gate detail: PJM's proposal now requires site control, permit matrix verification, technical data, and a \$30,000/MW readiness deposit before a project can enter the Screening Window at all. This is a materially higher bar than the current application process, and ACP has not seen an assessment of how this threshold affects queue entry for smaller or earlier-stage generation projects relative to well-capitalized large-load developers.
Earthjustice	PJM's proposal to substantially reduce interconnection study timelines is encouraging, but PJM must also ensure that any new interconnection study process is compliant with Order No. 2023. It is especially important that PJM ensure that study timelines are binding and backed by a robust system of penalties for study delays and that adherence to study timelines is not subject to the "reasonable efforts" standard. Likewise, PJM must study energy storage resources with the realistic modeling assumptions FERC required in Order No. 2023. We especially urge PJM to closely review FERC's decisions on its several compliance filings to ensure that PJM's new study process is aligned with FERC's requirements.
Tangibl Group, Inc.	It is extremely important for PJM to provide as much information and consultation as possible to PJM stakeholders and project developers in regard to any proposed new PJM planning process. This proposed new planning process will bring significant changes to the current PJM interconnection process, and PJM generation project developers will need to clearly understand the ramifications of any proposed changes to the PJM interconnection process so they can make the most appropriate business and project development decisions going forward. Also, PJM should strongly consider leaving the current Surplus Interconnection Service as it currently is as trying to fit this into the proposed new combined planning process will likely cause unintended consequences (i.e. surplus interconnection requests receiving significant cost allocations) that could render the process useless, which is problematic considering how PJM needs as much additional dispatchable generation to come online as quickly as possible. Furthermore, a new planning process is an opportunity for PJM to make material changes to the Generation Interconnection process to enable the speed that PJM is striving to achieve. This can include reevaluating scrutiny on application details and necessary dynamic modeling. Please consider the practical limitations of developers when developing any new rules.

Electranet REP I, LLC	Datacenters typically plan for diesel backups in their campus architecture designs which are often configured for open-transition operations and are non-grid-paralleling, requiring a momentary, complete disconnection from the grid before they can safely pick up their load. When dropping a large point load, this brief interruption can produce voltage spikes and other transient disturbances that degrade overall grid power quality, such as in Dominion as PJM presented. I think these risks can be mitigated with closed-transition, synchronized configurations, which allow onsite generation to carry load in a controlled manner (and more gracefully ramp load down in response to required curtailment orders such as from IRAS) while remaining synchronized with the grid, rather than abruptly disconnecting a large block of load from the system.
ENGIE Energy Marketing NA, Inc.	Storage Should Be Eligible for Netting on the Same Basis as Generation; Any Threshold Should Cap Load Netted, Not Gross Load or Facility SizeThe Behind the Meter Generation definition refers only to a "generation unit" and does not address storage, even though storage discharging to offset load without exporting to or withdrawing from the Transmission System is functionally identical to generation for netting purposes. Data centers and industrial loads already deploy on-site batteries for ramp compliance, voltage ride-through, and reliability, and these assets are already metered at the point of interconnection. ENGIE requests that PJM confirm that the BTMG and Co-Located Load definitions extend to storage operated in a manner functionally equivalent to generation, and that PJM specify how each storage operating mode will be treated for netting purposes rather than confirming eligibility in the general case. In particular, PJM should address storage charging from the Transmission System, storage charging from co-located generation, storage discharging to reduce the site's withdrawal, and storage exporting to the Transmission System, and should make clear which of these modes count toward or against the amount of load netted. ENGIE further requests that PJM confirm that a single storage facility may be split between a Capacity Resource designation and a BTMG or co-located designation, with the megawatt quantity assigned to each role identified separately and supported by settlement-quality metering and telemetry sufficient to distinguish the two roles in real time, so that the same megawatts cannot be counted both toward a capacity obligation and toward load netting.ENGIE appreciates PJM's confirmation that the Section 34.2 threshold is applied to the amount of load netted rather than to gross load or gross facility size, and that resources qualifying under the grandfathering provisions may net above that amount. ENGIE asks that PJM carry the same principle through to storage, so that eligibility is determined by the metered relationship between a site's load and its on-site resources rather than by the gross size of the facility, and so that the threshold is not administered as an all-or-nothing cliff that disqualifies a site entirely once it is exceeded. Because the threshold is applied cumulatively across a single electrical site, PJM should also define how that site boundary is drawn before the threshold can be applied predictably. ENGIE requests that PJM clarify what constitutes a single electrical site for purposes of the one-mile aggregation rule, how affiliation among facilities is determined where separate buildings, meters, or delivery points exist, and whether a facility developed and energized in later phases, potentially across different delivery years, can change or reopen the netting treatment already established for an earlier phase. Without that clarity, a site cannot determine its netting eligibility at the time it commits capital, and the 50 MW level sits below the scale at which co-located load, generation, and storage already operate.
1. Madison Fields Solar Project, LLC 2. Martin County Solar Project, LLC 3. Marion County Solar Project, LLC 4. Elkhart County Solar Project, LLC 5. MP2 Energy LLC 6. MP2 Energy NE LLC dba Shell Energy Solutions 7. Shell Energy North America (US), L.P.	See answer to Question 2 on how PJM will ensure cost certainty with new phases for developers.

1. Constellation Energy Generation, LLC 2. Constellation NewEnergy, Inc. 3. Handsome Lake Energy, LLC 4. Calvert Cliffs Nuclear Power Plant, LLC 5. Champion Energy Marketing LLC 6. Champion Energy Services, LLC 7. Champion Energy, LLC 8. North American Power and Gas, LLC 9. Calpine Bethlehem, LLC 10. Calpine Energy Services, L.P. 11. Calpine Energy Solutions, LLC 12. Calpine Mid Atlantic Marketing, LLC	Constellation appreciates the opportunity to provide additional feedback following the 9/16 Co-Located Load Order Workshop. We also appreciate PJM's clarification during the workshop that an applicant may identify a generation/load pair at the application stage, that the operational relationship between the resources may influence how the configuration is studied, and that PJM generally intends to account for those characteristics in its analysis. While these clarifications are helpful, additional detail is necessary to ensure PJM's proposal fully captures both the timing and cost benefits of configurations in which generation and load are contractually and operationally paired. Indeed, FERC pointed out in the ANOPR Show Cause that the impacts on the transmission system may be reduced through such pairings and that can accelerate the interconnection timing and reduce costs overall. But while PJM's proposal helpfully consolidates studies into an approximately 12-month integrated process, it remains unclear how the proposed framework will ensure that such paired configurations receive appropriate recognition as FERC envisioned for their reduced incremental transmission impacts when determining study scope, Network Upgrade needs, and cost responsibility. Constellation supports PJM's objective of developing an optimized transmission plan; however, a fully optimized plan should reflect requested service in both the study scope and resulting costs. A generation-load configuration that accepts enforceable limitations on injections, withdrawals, or other operating parameters should not be studied or assigned costs as though the generating resource and load were seeking full, independent deliverability rights. The operational relationship between paired load and generation should be reflected before PJM identifies the transmission "harms" that the optimized plan must solve. Otherwise, there is a risk that PJM could identify transmission needs that would not arise under the actual enforceable operating configuration of the paired project. Constellation appreciates PJM's clarification during the workshop that a customer could request more limited treatment and that would be captured in the study process. We encourage PJM to make that principle explicit in the proposed framework at the next workshop and ultimately in the governing Tariff provisions. Constellation's Load-Contingent New Capacity at Existing Plants (LCEP) proposal demonstrates why the configuration details between paired load and generation are important. LCEP is not simply a proposal to place a generator and load into the same study cluster. It pairs new generation with commensurate new load at the same POI as an existing generation resource and uses enforceable operational controls to ensure that combined net injection does not exceed the existing generator's interconnection rights. The proposal therefore leverages an existing POI and the maximum/minimum injection conditions that have already been studied, rather than requesting incremental injection capability. That feature can provide more than just a timing benefit. By leveraging existing interconnection facilities, existing studies, and an already-established transmission-system envelope, an LCEP-type configuration can potentially provide greater study and cost certainty, reduced exposure to Network Upgrade delays, and a more predictable commercial timeline. Constellation's LCEP proposal specifically explains that transparent and tailored study procedures are necessary to benefit from the efficiencies associated with an already-studied POI that is in operation and not lost through unnecessary repetition of the standard interconnection process, and FERC favorably described the LCEP proposal in the ANOPR Show Cause. For these reasons, Constellation believes a dedicated LCEP fast track naturally fits within PJM's consolidated approach, allowing PJM to leverage transmission capability that already exists while still conducting any analysis necessary to ensure reliability. If PJM believes its proposed consolidated framework fully captures the benefits associated with LCEP and similarly paired generation/load concepts, Constellation encourages PJM to incorporate off-ramps for accelerated agreements within the study process. Specifically, where screening or early study results demonstrate that a project's requested rights and enforceable operating limitations materially reduce its incremental transmission impacts, the project should be eligible to advance to agreement once PJM has completed the studies necessary to confirm reliability and establish the applicable operating controls. Such projects should not remain in the broader cluster study solely for procedural reasons. This approach would not require PJM to establish multiple separate queues or exempt projects from reliability review. Rather, PJM could maintain a common entry process while tying the scope and duration of the study to the rights requested and the incremental transmission impact demonstrated by the project. That would preserve the benefits of PJM's consolidated framework while also accommodating the type of tailored treatment contemplated by LCEP. Constellation also encourages PJM to provide several examples at the next workshop explaining how various generation/load configurations would navigate the new interconnection process, including opportunities for LCEP arrangements. Explaining how different generation/load configurations would interact with the TO process, application requirements, screening evaluations and turns, SIS assumptions, identified Network Upgrades, cost allocation methodologies, interim and final service rights, and resulting interconnection agreements would provide valuable clarity regarding the implementation of the proposed framework. Such examples would help stakeholders understand whether, and to what extent, the proposed framework accommodates LCEP-type arrangements and other configurations involving operationally and contractually paired generation and load that FERC contemplates.
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1. Calibrant Energy 2. Camus Energy	While PJM Staff has provided helpful description of many aspects of the proposed New Service Request process, Staff has yet to provide sufficient clarity on the intended treatment of flexible loads and the coordination of PJM and TO-level study of large loads. Both issues are fundamental to creating commercially viable pathways for the integration of large loads and to meeting the directives of FERC's June 18 orders. We appreciate Staff's indication that the September 30 workshop will address the study of the new transmission services approved in the Co-Located Load Docket. Given the limited time remaining ahead of PJM's planned mid-November filings, we encourage Staff to provide sufficient detail to enable meaningful feedback, including draft tariff language where feasible. As described in prior comments, we recommend that Staff consider the following in its development of a study process for non-firm transmission services: 1. A customer considering Interim NITS or Non-Firm Contract Demand (NFCDD) Service requires upfront transparency into curtailment thresholds and trigger events. A large load must understand the categories of constraint that could result in a requirement to reduce system withdrawals prior to electing that non-firm service (see our August 28 Survey Response for a list of relevant parameters). Without this clarity, customers cannot reasonably anticipate the limitations of the service or justify investment in the controls, onsite generation, or other technology enabling load flexibility. These curtailment parameters should recognize the flexibility of large load customers to adjust withdrawals with granularity beyond a drop to a firm service level. Curtailment requirements limited to binary "on/off" interruption will understate available flexibility and will exclude the load responses most beneficial to the customer and most useful to the system operator. Required curtailment in operations should reflect the specific constraints identified in the study of the load and the level of service that the load has taken. In the September 16 workshop, Staff indicated that the Interim Deliverability Schedule (the Schedule) provided to large load customers taking Interim NITS would provide annual MW of firm and non-firm service. PJM must also define the parameters of the curtailment that will apply to the customer over the course of the Schedule. The same logic applies to the information that must be provided to a customer considering NFCDD Service before the customer elects that service. 2. The study process should enable limited adjustment to new transmission service requests at defined decision points. During the discussion on September 16, Staff questioned the feasibility of accommodating requests to modify the service identified in an initial application. As noted in prior comments, we encourage Staff to enable large load customers to seek limited modification to new service requests at established decision points, e.g., adjusting a proposed combination of NFCDD Service and Firm Contract Demand Service. We propose such changes to be equivalent to the opportunity afforded new generators to reduce the CIRs requested in the generator interconnection process. As in the current generator interconnection process, restrictions on allowed changes could be structured in a manner that avoids disruption to subsequent study. 3. TO- and PJM-level study of flexible large loads (meaning loads that can reduce system withdrawals with or without generation) must be coordinated to provide an efficient pathway to interconnection. Staff offered high-level explanation of a proposed sequence linking TO-level review of large load interconnection requests and PJM-level study of new transmission service, including a requirement for TO approval to proceed at the Application Gate (September 16 Show Cause presentation at slide 9). Boundaries of these proposed stages of review remain unclear, as does the handoff of inputs from one level of review to the other. For example, it is unclear how load flexibility identified to avoid constraints in the process of TO-level study would inform PJM's study of new transmission services for that same load. We urge PJM to further clarify under the proposed New Service Request process the intended distinction between the constraints and upgrades studied at the TO level vs. those studied at the PJM level. A diagram may be useful in conveying this delineation. In clarifying the interaction of TO- and PJM-level study, we urge Staff to seek pathways to accelerate the study of flexible large loads, including loads paired with generation. We share concerns other parties have voiced in comments and in advancing "alternatives" that folding the study of all large loads into the interconnection process with all new generation could produce undue delay. Even in the "best-case" 12-month timeline put forward, the consolidated study process falls short of FERC's suggestion that PJM consider study accelerated to the order of 60-90 calendar days (Large Load Show Cause Order at paragraphs 63-64). This accelerated timeline is appropriate for resources capable of adjusting withdrawals to minimize or entirely avoid triggering network upgrades. Whether within the proposed New Service Request process or a separate track, we urge Staff to study transmission service for flexible loads in a manner consistent with the more limited system impact of those loads. At minimum, we urge PJM to consider "exit points" that enable service agreement execution for flexible loads (including generation with paired those loads) ahead of the 12-month cycle's completion. Other RTOs considering a more accelerated process for the study of large loads (e.g., MISO) may provide a useful model for delivering results similar to an Interim Deliverability Schedule following the 4-month Screening Process and ahead of the full System Impact Study.
RMI	The goals of a shorter and more streamlined interconnection study process are laudable; in order to best understand how this process would accommodate different types of interconnection requests (or transmission service levels, for loads), it could be helpful if PJM provided illustrative examples for certain types of requests and how they would be treated in the study process – for example, energy-only vs NRIS generation requests, surplus interconnection service requests, flexible loads, and co-located load/gen pairs.
EDF power solutions Development, Inc.	Stakeholders are very interested in the Readiness Deposit requirements through the new process. We note that DP1 is only 1 week long, which is too short to submit new security or amend existing security to a higher amount. It would be highly beneficial for PJM to provide some examples of security posting requirements for both load and generation interconnection projects under these proposed new rules.

	Forecasting out deliverability is a good idea. Attention to the planned schedule of project in-service dates will be an important input into any such forecast. On slide 12, it is stated that "PJM will offer select projects the option to withdraw with a full refund of their readiness . . ." PJM should set criteria that are clear to all in what situations this would apply - the way it currently reads it seems somewhat up to PJM discretion. Many of our prior submitted comments following the first show cause order workshop are still valid. We will not repeat those here but do want to reiterate many of those points. Some of the concepts in the proposal are good ideas but in some cases need some more detail for stakeholders to become comfortable with the approach.
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September 16 Co-Located Load Order Workshop Stakeholder Feedback Poll: Question 2

Company Name	Based on the information provided at the September 16 Co-Located Load Order Workshop, what additional questions do you have?
American Clean Power Association	Deposit cap methodology: How did PJM determine the \$25,000/MW cap on Decision Point 1 exposure? Is this cap fixed, or will it be revisited if actual reliability cost estimates run materially above PJM's \$20,000/MW illustrative example? Decision Point 3 thresholds: PJM's own materials describe the Final Agreement true-up test as requiring the IRR estimate to be "XXX% or more" of the Decision Point 3 estimate, with the percentage not yet specified. When will PJM propose this threshold, and will stakeholders have an opportunity to comment on it before the November filing? Cost allocation methodology: For a Network Upgrade or backbone facility jointly identified through a cluster study involving both large load and generation, does the upgrade retain its existing RTEP/Schedule 12 cost allocation treatment, or would some or all of the cost be assigned to the generation interconnection customer(s) in the cluster? If assignment to generation is contemplated, what causation methodology would PJM use to determine each participant's share? Supplemental Project status: Do large-load-driven upgrades currently in progress, or newly identified under the September 16 proposal, retain their Attachment M-3 Supplemental Project designation and zonal cost recovery — or does entering the new cluster study convert their classification and cost treatment? Proximity scope: What is PJM's specific rationale for applying the new cluster process and deposit structure to non-proximate large load, given that the Show Cause Order's joint-study directive is tied to electrical proximity and enforceable output limits? Would PJM consider limiting the new structure to proximate, output-limited pairs consistent with the Order? Modeling and computing capability: What is the current status and validated performance of the enhanced computing power and updated models underlying the Screening Window's 16-week timeline? What testing or pilot data supports using that capability as the basis for a binding financial milestone clock? Milestone consequences: If PJM's modeling and computing tools do not perform as represented — slower turnaround, lower fidelity, or required rework — does the Screening Window's financial milestone clock adjust, or does the resulting risk and cost fall entirely on the interconnection customer? Application Gate threshold: What analysis supports the \$30,000/MW readiness deposit and the site control/permit/technical data requirements at the Application Gate? Has PJM assessed how this threshold affects queue access for earlier-stage or smaller developers relative to large-load applicants? Interconnection cost transparency: Decision Point 2 requires 100% of interconnection (direct-connect) cost, determined during Turn 2's Direct Connect Intercon study. What visibility, if any, will a developer have into that cost estimate before Turn 2 concludes, given that Turn 1 provides no interconnection cost information at all? Interaction with Scheduled Interim Deliverability: How does the proposed Scheduled Interim Deliverability schedule interact with Provisional Interconnection Service for generation serving co-located load, given FERC's April 2026 order clarifying PIS availability in that context? Are these two mechanisms intended to operate together, or does a project have to choose between them? Contingent facility and restudy exposure: In the new cluster structure, how are contingent facility costs and restudy triggers allocated when one participant — load or generation — withdraws or changes its request after Turn 1 or Turn 2 upgrades have been jointly identified? Filing timeline: Given the open cost allocation, Decision Point 3 threshold, and modeling-validation questions above, what is PJM's basis for targeting a November filing? Would PJM consider a phased approach that resolves cost allocation and Decision Point 3 thresholds, and pilots the modeling capability, before filing the broader structural changes?
Earthjustice	Please spend some time in an upcoming stakeholder meeting explaining how PJM plans to ensure that its new interconnection process remains compliant with Order No. 2023.
Tangibl Group, Inc.	What is PJM's plan to allow PJM stakeholders a forum/venue to provide meaningful feedback and suggested changes to the proposed new combined planning process before PJM files its proposal at FERC filing in mid-November? As stated in the answer to the previous question, the proposed new combined planning process will bring significant changes to the current PJM interconnection process, which will correspondingly affect PJM generation project developers' business models and investment decisions, which will in turn affect both the level of future generation investment and overall PJM resource adequacy & grid reliability.
Electranet REP I, LLC	1. Separate from needing to ride-through grid power quality issues, when LCLs are required to curtail, such as from IRAS or non-firm transmission services like Interim NITS, would PJM's proposed ramp-rate requirements for LCLs effectively render concerns on abrupt disconnection of large point loads moot? 2. Could PJM clarify if non-exporting, grid-parallel, closed-transition onsite generators installed behind-the-meter will be required to go through the generator interconnection cluster study process? If not, could PJM specify what alternative, streamlined studies, i.e., targeted stability, short-circuit, and steady-state analyses, would be required?

ENGIE Energy Marketing NA, Inc.	A large load cannot make informed investments in controls, storage, or other flexibility technologies without understanding when, how often, and for how long curtailment may occur under a non-firm service product. ENGIE requests that PJM model and publish expected curtailment frequency and duration based on historical system conditions, and identify the specific conditions that trigger curtailment, including transmission constraints, IROL conditions, capacity-related reliability concerns, or other system needs. ENGIE further requests that PJM separately identify the operational characteristics of each transmission service option, including Interim NITS, Non-Firm Contract Demand Service, and any future flexibility-based transmission product, rather than describing such services collectively. At a minimum, PJM should provide the operational triggers, implementing entity, notification requirements, required response time, required MW reduction, ramp rate requirements, maximum duration of curtailment, restoration procedures, and whether partial curtailment is permitted. Finally, ENGIE requests that PJM confirm that a curtailed co-located load may continue operating using energy supplied by its own co-located generation or storage, provided the site remains within its directed grid-withdrawal limit. Curtailment of transmission service should not require the curtailment of behind-the-meter energy supplied by on-site resources that do not increase withdrawals from the Transmission System.
1. Madison Fields Solar Project, LLC 2. Martin County Solar Project, LLC 3. Marion County Solar Project, LLC 4. Elkhart County Solar Project, LLC 5. MP2 Energy LLC 6. MP2 Energy NE LLC dba Shell Energy Solutions 7. Shell Energy North America (US), L.P.	How will PJM ensure meaningful cost certainty after the new "DP2", including: (1) a defined threshold for acceptable cost increases, (2) penalty-free withdrawal rights when that threshold is exceeded, (3) protections against cost waterfalling from later project withdrawals, and (4) transparent treatment of forfeiture funds and avoided upgrade costs resulting from attrition?
1. Constellation Energy Generation, LLC 2. Constellation NewEnergy, Inc. 3. Handsome Lake Energy, LLC 4. Calvert Cliffs Nuclear Power Plant, LLC 5. Champion Energy Marketing LLC 6. Champion Energy Services, LLC 7. Champion Energy, LLC 8. North American Power and Gas, LLC 9. Calpine Bethlehem, LLC 10. Calpine Energy Services, L.P.	Please see several clarifying questions below: 1. If the screening process confirms a paired generation/load configuration has limited incremental transmission impacts and the proposed operational controls are sufficient to maintain applicable system limits, could PJM provide an off-ramp to accelerated agreement rather than requiring the project to remain in the process for the entire 12-month period? 2. PJM's proposal describes its proposed new process as identifying system upgrades that "fix all harms" across the cluster. How would PJM define those harms? What are the thresholds? 3. Could PJM provide additional clarification on how the "harms" identified in the studies will be cost allocated and specifically how this study process will integrate with the current RTEP process and supplemental projects? 4. PJM stated during the workshop that a generation/load pair may identify in its application as codependent and that this can change how the configuration is studied. Could PJM more specifically explain how such a pair will be represented in the screening and System Impact Study? 5. What constitutes sufficient "TO approval to proceed," and is this standard for co-located or paired load/generation? What technical information must be established at the TO level before PJM will accept the paired operating configuration as a study assumption? 6. If one member of a paired generation/load pair withdraws, and the remaining member finds a new pairing, what portions of the analysis could carry over to the new pairing or would the new pairing have to reapply during the next application window? 7. How would the State Agreement Approach fold into this proposed consolidated process? 8. Can PJM provide more clarity on potential restudies and the threshold for how PJM would determine when a restudy is required and how long the restudy process would be? 9. PJM noted a new application cycle would not start until the previous cycle was completed, but when asked about restudies and withdrawn projects at the agreement phase, stated there would be some cycle overlap. Could PJM please elaborate on how delays in the previous cycle would impact new cycle applications; i.e., will PJM just extend the application window and delay the screening window process or will they proceed despite restudies in previous cycle.

11. Calpine Energy Solutions, LLC 12. Calpine Mid Atlantic Marketing, LLC	
1. Calibrant Energy 2. Camus Energy	We encourage Staff to address the following questions during the September 30 workshop: 1. During the September 16 workshop, Staff observed that the large load developer is intended to be the entity responsible for bringing a large load through the New Service Request process, pending further development of relevant logistics. a. How does this intent interact with definitions of “Eligible Customer” summarized in the August 18 “Overlap of Large Load” presentation, including the observation that an LSE would not be required to offer the new transmission services to retail customers (slide 8)? b. Is PJM's intent that the transmission service agreement would be executed with the large load customer? 2. Staff noted the expectation that the interconnection process for large load customers would commence with the TO and proceed to review of the transmission service request at PJM. a. Please clarify how the study of “Transmission Service” is distinct from the study of new load interconnection? I.e., what is PJM's intended demarcation between the study of “Transmission Service” within the New Service Request process and the study of new load interconnection at the TO level? b. To the extent certain upgrades are implicated in both study processes, how would this interaction be addressed? c. How will load flexibility be studied in the New Service Request Process (both for NFCD and for Interim NITS customers)? How will studied flexibility translate into operational obligations? d. How would load flexibility identified in a TO interconnection process to avoid local or sub-transmission constraints interact with PJM's study of the load flexibility necessary for the new transmission services? How will PJM study load flexibility commitments made at the TO-level? 3. Where and how does PJM intend to provide transparency into curtailment thresholds and triggers applicable to customers taking NFCD Service or Interim NITS? a. Will an Interim Deliverability Schedule specify curtailment parameters and thresholds (beyond firm vs. non-firm MW in each year)? b. Does a customer need to elect interim NITS or will the customer automatically receive Interim NITS if eligible? c. In determining the flexibility required of a large load electing NFCD Service or Interim NITS, would PJM isolate the scope of required curtailment to applicable transmission system constraints? Or would the curtailment assigned to NFCD and Interim NITS customers also reflect resource adequacy constraints? If the latter, how would a new large load that contracts with off-site accredited capacity under a "BYONC" arrangement be treated differently? 4. For customers electing NFCD Service upfront: a. Will the customer be able to specify flexibility on a granular basis, e.g., to offer the ability to curtail for a certain number of hours per year? Or does PJM propose that a customer would only select between binary “firm” vs. “non-firm” transmission service? b. How does PJM propose to account for the load flexibility identified in the customer's application in the Screening Process and during the System Impact Study phase? 5. Under what parameters would PJM allow customers to modify the level of firm service requested in an application, beyond the election of Interim NITS? E.g., a request to increase NFCD and reduce FCD, similar to the modification requests allowed at prescribed decision points for new generators under current interconnection procedures.
RMI	• For the proposed simplified screening window, which analyses would be excluded relative to the current study process? What information will participants receive at each decision point within the simplified screening window (DP1 and DP2)? • What level of accuracy does PJM expect participants to have in the cost and schedule estimates between the simplified screening window results (at DP2) and execution of a final interconnection agreement, particularly with respect to the potential for material changes between the screening study and the SIS? • Can PJM provide more detail on if and how it is considering using currently available commercial software solutions for automating or managing the workflow for this new interconnection study process?

	• How would compliance with the proposed 12-month timeline be monitored and addressed if studies exceed the target schedule? (How likely are study delays, and how would they be minimized?) • For certain interconnection/transmission service options, like energy-only resources, flexible loads or co-located gen/load, would PJM have off-ramps or specific network upgrade allocations that reflect those customers' different service levels? If so, does PJM intend to specify these?
EDF power solutions Development, Inc.	How will this process, if implemented, overlap with the existing processes currently in place for Cycle 1? A timeline of Cycle 1 and the proposed new process would be helpful in understanding this relationship As for the deliverability forecast, how will project in-service dates be computed - will they be solely based on what is submitted by the developer or will there be some dependency on the expected timeline to build out the physical interconnection facilities? We'd recommend the latter. On slide 14, it appears the new process would no longer implement the concept of 'contingent facilities' - wouldn't certain facilities potentially still fall under this description, such as if approved RTEP project has longer lead time? That upgrade would not be included in base model but could still be considered mitigation (and thus contingent)? If that is not correct can PJM try to explain more fully how this could work?



Michele Greening & Mollie Lacek
Stakeholder Affairs
PJM

Via E-mail

September 22, 2026

Re: Co-Located Load Order Workshop: Questions in Response to 9/16 Presentation

Dear Michele and Mollie,

On behalf of Corporate Energy Buyers Association (CEBA), American Clean Power Association (ACP), and Solar Energy Industries Association (SEIA), please find below questions for PJM staff regarding its proposal—as presented at the Sept. 16th Co-located Load Order Workshop—for a combined interconnection queue for load and generation in response to FERC's Large Load Show Cause Order. We are submitting these questions by email as we missed the 5pm ET deadline today to submit via the Qualtrics tool.

We understand that some topics below are those that PJM staff has already reserved for discussion at that next meeting, including cost allocation and the Reinforcement Cost Certainty Framework. The questions we offer below aim to help PJM staff craft its presentation at the Sept. 30th workshop and ensure that stakeholders have a complete understanding of the implications of PJM's proposal.

Thank you for the continued opportunity engage with PJM staff as this proposal takes shape.

Sincerely,

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Question 2: Based on the information provided at the September 16 Co-Located Load Order Workshop, what additional questions do you have?

Topic 1: Alternatives

- What alternative ideas did PJM consider before arriving at its preferred concept and what were the tradeoffs that led to PJM arriving at its preferred concept of combining large load TSRs and generator interconnection requests into a single queue? For example, why didn't PJM pursue a combination of processes akin to the Expedited Project Review in MISO and HILLGA in SPP?
- Is PJM concerned that, between only just recently switching to the new Cycle process approved in 2022, implementing the directives in Order No. 2023, and now moving to a combined queue, it is creating even more queue instability? What other guardrails is PJM putting in place to ensure that load, generation, and transmission interconnection requests can successfully navigate these processes?

Topic 2: Regional Transmission Planning and Cost Allocation

We appreciate PJM's verbal commitment at the 9/16 workshop to preserving the benefits of comprehensive regional transmission planning. However, it remains unclear how PJM's proposal integrates with regional planning processes to ensure that outcome.

- Could PJM provide examples of the types of upgrades that could be identified through its proposed combined queue and how those upgrades will be fed back into regional planning processes (both RTEP and LTRTP)?
- Are there scenarios under PJM's approach where planning for near-term needs could crowd out opportunities to solve multiple needs more cost-effectively through a comprehensive solution that could only be identified through regional transmission planning?
- What load growth will remain in long-term regional transmission planning under PJM's concept, and how does that relate to the load growth that will be planned for through PJM's proposed approach?
- How will PJM identify and publish costs of large load-related upgrades versus upgrades associated with generation interconnection?
- How will upgrade costs be allocated between load and generation?

Topic 3: Study Mechanics

- To help us better understand the mechanics of PJM's proposed study approach, could PJM provide several examples showing how it will study: (1) paired load and generation (which is electrically proximate); and (2) unpaired load and generation?
 - In those examples, how will the study consider contingencies where loads or generation are offline?
- How will restudies be conducted in cases where: (1) load or generation in a pairing withdraws; and/or (2) unpaired load or generation withdraws? What are the expected impacts on upgrades in these scenarios?
 - If the paired load withdraws from the queue, are deposits paid by the generator refundable?

- How does PJM's approach reflect phased load ramp schedules? For example, if PJM's proposal relies on a 3-year case but a large load has a 5-year ramp schedule, how much of that new load will be studied in a given queue cycle?
- If the Screening Window confirms that an electrically proximate load-gen pairing requires no network upgrades (subject to the installation of necessary system protection controls), could PJM provide an off-ramp to accelerated agreement?
- Please clarify how a large load customer that invests in and contracts for distribution-connected DERs qualifying as a Peak Shaving Adjustment would receive appropriate recognition for enabling that incremental new capacity in the new combined large-load and generation study process. Specifically, how would PJM ensure that these resources are not excluded from potential queue or study benefits simply because they are not proceeding through the same PJM interconnection process as the associated large load?

Topic 4: Cost Certainty

- PJM proposes a \$30,000/ MW but is still determining the readiness deposit for generators. When will that information be available? What inputs is PJM considering in determining the readiness deposit?
- Turns 1 and 2 produce "preliminary, desk-site estimated system upgrade costs," which are subject to change during the subsequent System Impact Study. Yet, at the end of Decision Point 2 interconnection customers must post 100% security for upgrades that are fully at-risk.
 - Could PJM clarify how that promotes the goal of cost certainty?
- The Reinforcement Cost Certainty Framework (RCCF) does not appear to manage this risk of cost shifts that occur after Decision Point 2. Rather RCCF appears geared toward managing the risk of cost shifts occurring between Decision Point 3 and execution of an interconnection agreement at the end of the Final Agreement phase.
 - Is that a correct reading of the proposal?
 - Could PJM clarify what funds would be eligible for full refund under RCCF? Do readiness deposits include security posted at the end of the Application Gate as well as incremental security posted at subsequent Decision Points?

Topic 5: Next Steps

- When will PJM staff release tariff language for stakeholders to review?
- What is PJM's proposed timeline for implementing this new process? Would generation projects in Cycle 2 of the New Services Queue be affected, or would it apply to projects starting with Cycle 3?