BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Potential Regulations for Interconnecting Electric Loads	: :	Docket No. L-2025-3059032

COMMENTS OF THE COALITION FOR COMMUNITY SOLAR ACCESS, THE SOLAR ENERGY INDUSTRIES ASSOCIATION, AND ADVANCED ENERGY UNITED (“JOINT CLEAN ENERGY PARTIES”)

The Coalition for Community Solar Access (“CCSA”), the Solar Energy Industries Association (“SEIA”), and Advanced Energy United (“United”) (collectively, the “Joint Clean Energy Parties” or “JCEP”) respectfully submit these comments in response to the Pennsylvania Public Utility Commission’s (“Commission”) June 22, 2026 Secretarial Letter seeking comments on potential regulations governing the interconnection of electric loads, including large loads, in Docket No. L-2025-3059032.

CCSA is a 501(c)(6) nonprofit trade organization focused on supporting the community solar industry through legislative and regulatory efforts. CCSA’s mission is to empower every American energy consumer with the option to choose local, clean, and affordable community solar. CCSA works with customers, utilities, local stakeholders, and policymakers to develop and implement policies and best practices that ensure community solar programs provide a win for all affected stakeholders, starting with the customer. CCSA has over 120 member companies and has participated in regulatory proceedings before a number of state public utility commissions, including Pennsylvania, as well as at the federal level. Many of CCSA’s members develop community-scale solar and solar-plus-storage projects that require interconnection to electric distribution systems. CCSA advocates for its members’ interest in creating and expanding opportunities to develop distributed energy resources (“DERs”) sited close to load that enhance system resilience and reduce overall system costs.

SEIA is the national trade association for the United States solar industry. SEIA works to support solar energy by expanding markets, reducing costs, increasing generation reliability, removing market barriers, and providing education on the benefits of solar energy and energy storage. SEIA works with its 1,200 member companies and other strategic partners to advocate for policies that promote the aforementioned goals. SEIA’s member companies include manufacturers of solar and battery storage equipment; residential, community solar, commercial, and utility-scale developers; and installers, construction firms, investment firms, and service providers. SEIA’s members include over 30 companies located in Pennsylvania, and several national firms also conducting business in the Commonwealth of Pennsylvania.

United is a national industry association representing businesses that provide the full range of advanced energy and transportation solutions. We advocate for public policies that enable competition and work alongside our member companies to create economic opportunity, lower consumer costs, and bolster energy reliability and resilience across the country. Together, we are united in our mission to create an economy built on advanced energy. Advanced Energy United is online at AdvancedEnergyUnited.org.

I. INTRODUCTION

The JCEP appreciate the Commission issuing this Secretarial Letter when public utility commissions across the nation are grappling with how to maintain affordable and reliable service in a time of load growth. DERs such as battery storage, solar, electric vehicles, smart thermostats, and other technologies are best positioned to deliver needed capacity due to their speed of deployment and scalability. The December 18, 2025 Motion of Vice Chair Barrow, in which the Vice Chair proposed a "rulemaking to modernize the Commission's interconnection regulations," explicitly mentions DERs. The Vice Chair wrote that the rulemaking "would encompass a universal review of interconnection regulations for new load, uprates of existing load, *and distributed energy resources*."[1]

Unfortunately, the focus on DERs is notably absent from the list of questions provided in the Secretarial Letter. DERs are only explicitly mentioned in one question (question five). JCEP are concerned that the Secretarial Letter is missing an opportunity to conduct the "universal review" that Vice Chair Barrow called for in her Motion. This review should include regulations for the interconnection of DERs, not just load. Just as the Commission found that updates were needed to align Commission regulations with FERC Order No. 2222,[2] so too should the Commission update its interconnection regulations to meet the goals of that order. Omitting a review of interconnection regulations for DERs could limit the positive impact of the Commission's forthcoming final rule in Docket No. L-2023-3044115.

The Commission need not start from a blank slate. Neighboring New Jersey is already examining many of the same DER interconnection issues that warrant consideration in this proceeding. On February 3, 2026, the New Jersey Board of Public Utilities ("Board" or "BPU") issued a request for information[3] ("RFI") seeking stakeholder input on, among other things, whether and how to:

- Modify or waive existing regulations to improve the efficiency and speed of interconnecting new projects;
- Improve hosting capacity maps and facilitate project interconnection to 34.5 kV distribution lines;

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1 Emphasis added.

2 Docket No. L-2023-3044115, *Joint Motion of Chairman Stephen M. DeFrank and Vice Chair Kimberly Barrow* (Nov. 9, 2023).

3 N.J. Board of Public Utilities, Docket No. QO24030199, *Request for Information* (Feb. 3, 2026), available at: https://publicaccess.bpu.state.nj.us/DocumentHandler.ashx?document_id=1411021.

- Identify constrained circuits within utility service territories that should be upgraded to expedite and support DER interconnection; and
- Pursue other measures to support DER development on constrained circuits.

In response to the RFI, the JCEP submitted the following eleven general recommendations for the Board's consideration:

1. Establish enforceable interconnection study timelines with consequences for non-compliance;
2. Expand flexible interconnection options, including phased and dynamic interconnection;
3. Improve cost certainty through cost envelopes, contingency caps, and standardized cost-estimation methodologies;
4. Require applicants to demonstrate and continuously maintain site control to strengthen queue integrity;
5. Advance proactive distribution system planning and multi-beneficiary cost allocation;
6. Improve hosting capacity transparency and access to distribution system data;
7. Clarify and modernize the treatment of energy storage interconnection requests, particularly for front-of-the-meter storage;
8. Provide greater clarity and transparency regarding the jurisdictional classification of 34.5 kV lines;
9. Establish a Commission-level interconnection ombudsperson, supported by internal ombudspeople designated by each electric distribution company ("EDC");
10. Modernize interconnection rules for vehicle-to-grid ("V2G") and other bidirectional charging technologies; and
11. Streamline interconnection processes for residential DERs.

Further details supporting these recommendations are provided in the Joint Clean Energy Parties' comments submitted to the BPU in Docket No. QO24030199. Those comments, included as Appendix A hereto, describe specific reforms that may also inform the Commission's review of Pennsylvania's DER interconnection framework.

The JCEP note that the Commission last held a stakeholder collaborative on distribution generation interconnection processes in June 2022.[4] Although the information developed through that collaborative may remain useful, the record would benefit from a renewed opportunity for stakeholders to address current DER interconnection issues. Since 2022, interconnection best practices have evolved rapidly, and utilities, developers, and other stakeholders have gained substantial additional experience interconnecting DERs in Pennsylvania. That experience could

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4 *PUC Holding Discussions on Distributed Generation Systems* (May 31, 2022), available at https://www.puc.pa.gov/press-release/2022/puc-holding-discussions-on-distributed-generation-systems.

materially strengthen the record and help the Commission identify practical reforms to improve the efficiency, transparency, and consistency of the Commonwealth's interconnection processes.

Energy storage warrants particular attention as part of that review. Storage deployment has accelerated significantly since 2022, and the technology's ability to operate as both load and generation raises technical and procedural issues that conventional generation-only interconnection processes may not adequately address. The Commission should therefore consider how energy storage can be incorporated efficiently into Pennsylvania's interconnection framework, including how charging, discharging, export limitations, and operating controls should be reflected in interconnection applications and studies. In addition, the Commission should evaluate pathways for integrating storage into existing generation interconnection requests, such as adding storage to a solar project, without unnecessarily restarting or duplicating the interconnection study process, where such additions do not materially alter system impacts.

The need to modernize DER interconnection rules is especially timely with respect to bidirectional electric vehicle ("EV") charging. EVs operating in parallel with the grid can reduce peak demand, lower ratepayer costs, and absorb renewable generation that might otherwise be curtailed, benefits identified in the 2019 Pennsylvania Electric Vehicle Roadmap[5]. As interest in bidirectional charging has grown, several states have updated their interconnection frameworks to establish clearer pathways for these technologies. Maryland, for example, has advanced such reforms through enactment of the DRIVE Act[6] and adoption of comprehensive interconnection rules[7]. Without comparable updates, Pennsylvania's interconnection procedures may lack the EV-specific technical standards and review pathways necessary to support the safe, consistent, and timely integration of bidirectional charging systems.

Beyond broadening the focus of this stakeholder input process to include DER interconnection topics, JCEP's central recommendation to the Secretarial Letter is straightforward: **Any load interconnection framework should preserve the distinct technical treatment of load and generation while ensuring that both are evaluated against the same distribution system.** Large loads, distributed generation, and storage all depend on the same distribution infrastructure and planning assumptions. Rules governing new load should improve, not fragment, coordination

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[5] Pennsylvania Department of Environmental Protection, *Pennsylvania Electric Vehicle Roadmap* (Feb. 2019), available at https://files.dep.state.pa.us/Energy/OfficeofPollutionPrevention/StateEnergyProgram/PAEVRoadmap.pdf

[6] Advanced Energy United, *Power Grid International: Maryland Passes Bi-Directional EV Charging Law* (Apr. 4, 2024), available at https://advancedenergyunited.org/united-in-the-news/maryland-passes-bi-directional-ev-charging-law/.

[7] Zach Woogen, *Maryland Becomes First to Adopt Comprehensive Vehicle-to-Grid (V2G) Interconnection Rules*, Vehicle-Grid Integration Council (June 12, 2025), available at https://www.vgicouncil.org/articles/maryland-becomes-first-to-adopt-comprehensive-vehicle-to-grid-v2g-interconnection-rules.

with generation interconnection, particularly where collocated solar and storage can reduce net grid impacts and help mitigate the constraints large loads may otherwise create. These rules should also ensure that load forecasts are accurate and transparent, so that the Commission, EDCs, developers, and grid operators have clear insight into the growing grid needs.

II. RESPONSE TO COMMISSION QUESTIONS

These comments are divided into two parts. Part A answers questions 4, 5, 12, 13, and 15, which pertain to the relationship between load interconnection, generation interconnection, and distribution system transparency. Part B answers questions 6 and 7 which pertain to inputs to load assumptions.

A. The Relationship Between Load Interconnection, Generation Interconnection, and the Distribution System.

Question 4: If there is generation collocated with the load, should there be an expedited process for the generation to be interconnected at the same time the load is interconnected?

The JCEP strongly support a coordinated pathway under which generation collocated with load is studied and interconnected on a timeline aligned with the associated load and urges the Commission to design that pathway in a technology-neutral manner that fully accommodates solar and storage, including EVs. The objective is timing alignment, not queue preference: where collocated generation is studied on the basis of its actual net injection, and its curtailment and export-limiting capabilities are reflected in the study assumptions, the generation can be processed and energized alongside the load as a matter of design, without advancing it ahead of other projects in the queue.

The logic of coordinated collocation is straightforward and has been embraced at the federal level and across multiple grid operators.[8] Generation sited at or near the point of an interconnecting load can serve that load directly, reducing the net demand the grid must supply and thereby reducing the network upgrades the interconnection would otherwise require. The U.S. Department of Energy's Advanced Notice of Proposed Rulemaking on large-load interconnection expressly contemplates studying load and collocated generation together to enable efficient siting and minimize upgrade costs, and the Federal Energy Regulatory Commission ("FERC") has directed PJM Interconnection, L.L.C. to study collocated generation only to the extent of its actual intended injection to the grid rather than its full nameplate, so that a facility serving most of its output to an

[8] *PJM Interconnection, L.L.C.*, 193 FERC ¶ 61,217 (2025) (co-location order directing tariff revisions, including study of collocated generation to the extent of intended grid injection and acceleration of interconnection).

onsite load is not studied as though it exported at full capacity.[9] The Southwest Power Pool ("SPP") is an example of a grid operator that has moved in parallel to coordinate the processing of generation paired with large load, recognizing that load can be stood up far faster than the generation and transmission needed to serve it, and that coordinated processing closes that timing gap.[10]

Properly designed, this same principle can be applied to DERs when collocated with large loads. A solar-plus-storage system collocated with a large load can offset a meaningful share of that load's grid draw, shave its contribution to local peak, and provide controllable, export-limiting capability that reduces the upgrades the load would otherwise trigger.

The relevant benefits, however, need not be limited to resources physically located behind the same meter or on the same parcel as the large load. DERs located elsewhere on the same substation, or, where supported by appropriate system analysis, elsewhere within the EDC's service territory, may also provide capacity, peak-reduction, or other grid benefits that help mitigate the system impacts associated with new large loads.

A coordinated pathway should be available to these resources on equal terms, evaluated on the basis of the capacity they actually intend to export rather than their full nameplate rating, and crediting export-limiting and controllable operation. What matters is that the generation be studied and energized on a timeline aligned with the associated load, so that the clean, flexible resources best positioned to mitigate the grid impact of large loads are not stranded behind a slower, separate process.

The JCEP emphasize one critical guardrail: a coordinated pathway for generation collocated with load must not come at the expense of generation interconnection requests that are not collocated with load. The coordinated track should draw on dedicated process capacity, aligning the timing of collocated generation without reordering, deprioritizing, or delaying the standalone generation queue. Distributed solar and storage advancing through the generation interconnection process must continue to be studied and processed on reasonable, transparent, and nondiscriminatory timelines. Any accommodation for large loads should be additive to, not extracted from, the resources and timelines available to the broader queue.

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[9] U.S. Dep't of Energy, Secretary's Direction to FERC re: Interconnection of Large Loads (Oct. 2025); FERC, *Interconnection of Large Loads to the Interstate Transmission System*, Docket No. RM26-4-000.

[10] *See* Sw. Power Pool, Inc., 194 FERC ¶ 61,031 (2026) (accepting Southwest Power Pool's High Impact Large Load and High Impact Large Load Generation Assessment tariff revisions, which pair "shovel-ready" generation with large loads and permit the associated generation to interconnect using a capacity accreditation limited to the forecasted load it serves).

Question 5: Some EDCs provide online portals for the interconnection of DERs. Should the same be provided for load-interconnecting applicants to submit all applications and supporting documents? Please list the benefits or drawbacks.

The JCEP encourage the use of an online portal for load interconnection applications. Managing the interconnection process via email, with no centralized portal to track application status, adds unnecessary delay when faster, more efficient options are available. In a similar theme to the answers to Questions 4 and 13, the JCEP prefer load and generation customers to be treated similarly. If utilities are providing portals for generation customers, an additional portal or separate application within the existing portal ought to be feasible to implement. The benefits that apply to collecting generation interconnection applications online will also apply to load customers. A sample of the potential benefits include:

- An online portal could be integrated with the EDC's other software systems, metering and eventually billing systems – reducing the need for manual data entry across systems which removes additional queues and reduces the likelihood of human error. Online applications also reduce the risk of losing an application in a more manual process.
- The online portal could include customizable applications catered to project specifics, with branching questions and pop-ups providing more immediate feedback to the applicant, for example indicating an incompatibility in project size or location and thus submitted applications will be partially pre-reviewed.
- The portal may also allow for automated updates or communications to the customer notifying them of queue progress, expected timeline, or project status. The customer will also have the ability to return to the portal to seek further information or provide requested materials.
- The reporting and analytics offered by online portals enable EDCs and the Commission to monitor and export reports on the universe of applications and the review process. These analytics may be generated on demand and may be used to track interconnection queues.

The use of an online portal for load and DER interconnection applications allows for greater control over the application process, a smoother user experience, and insights via analytics. Load customers and DER customers should both submit interconnection applications on an online portal.

Question 12: Should there be prescribed timelines and timeframes for completing the various steps in the load interconnection application review process? If so, address process steps and reasonable completion times, studies that may be required, overall review timeframe, review

timeline for collocated load and generation requests, and required actions if an EDC exceeds its expected review timeline.

While Question 12 is primarily directed at load interconnection application reviews, we would be remiss to not flag a parallel and equally pressing need: updating the Commission's DER interconnection application review process to include clear, enforceable timelines for each stage of review. Predictable review timelines are essential to maintaining an efficient queue and giving developers, customers, and utilities the certainty they need to make sound investment and project development decisions.

The current rules contain deadlines for some stages of DER interconnection review, but these are non-comprehensive and omit the phases where delays are the most consequential. In particular, the existing rules lack binding timeframes for EDCs to complete studies at various stages of review. While EDCs often provide timeline estimates in study agreements, these estimates are non-binding and unenforceable. Developers have reported studies taking as long as 18 months to complete. This turns a study phase intended to take weeks or months into a de facto queue-blocking delay with no recourse. The Commission should ensure that differentiated, binding and comprehensive timelines are attached to each existing review level (Level 1 through 4).

Binding review timelines should be paired with accountability measures and a clear dispute resolution mechanism. Where an EDC exceeds an established review deadline, the Commission should require corrective action, such as mandatory status reporting, fee waivers or credits, or an expedited path to Commission intervention, to ensure that queue delays do not persist indefinitely. For a workable model, the Commission should look to New York's Standardized Interconnection Requirements, which govern the state's Coordinated Electric System Interconnection Review process.[11]

Question 13: Should there be separate queues for both generation and load interconnection requests? Why or why not?

Yes, but the distinction should be administrative, not operational. Separate queues are useful for tracking different types of requests, applying appropriate milestones, and preserving transparency. But load and generation cannot be planned as though they affect different systems. They draw on, and can relieve, the same feeder, substation, transformer, and protection constraints. The Commission should therefore require separate administrative queues that are evaluated against a single, integrated view of distribution system capacity.

Separate processes are warranted because load and generation interconnections raise different engineering questions and have historically been governed by different procedures. Load requests evaluate whether the system can reliably serve new demand, particularly at peak. Generation requests evaluate export capability, reverse power flow, voltage, protection, fault current, and related operational impacts. Separate queues also improve transparency by giving load applicants

[11] N.Y. State Pub. Serv. Comm'n, *New York State Standardized Interconnection Requirements and Application Process for New Distributed Generators and/or Energy Storage Systems 5 MW or Less Connected in Parallel with Utility Distribution Systems*, Case 24-E-0621, § I.C, Steps 4–6 (effective Feb. 9, 2026) (establishing the Coordinated Electric System Interconnection Review process).

visibility into service capacity and load-driven constraints, while giving generation applicants visibility into export capacity, hosting constraints, queued generation, and upgrade dependencies. Collapsing these distinct reviews into a single undifferentiated queue would obscure the information applicants and EDCs need and would not serve either category of interconnection request well.

The Commission should also ensure, however, that separate queues must not become siloed processes. Load and generation rely on the same distribution infrastructure and can materially affect the interconnection of one another. New load may create export headroom; generation or storage may reduce net load or defer upgrades; and storage may operate as both load and generation. Accordingly, queue administration should be distinct, but system modeling must be integrated.

The Commission should therefore adopt a two-part framework that separates administration while integrating analysis. First, EDCs should maintain separate administrative queues for load and generation. Each queue should track application date, queue position, project size, project type, study status, milestone status, required deposits, anticipated upgrade needs, and expected completion dates. These queues should support transparent reporting and allow Commission Staff to monitor whether EDCs are processing requests in a timely and non-discriminatory manner. Second, EDCs should use integrated engineering models that account for both queued load and queued generation when evaluating distribution constraints, available capacity, upgrade needs, and project impacts. This is especially important for large loads, storage projects, limited-export projects, and collocated load-generation configurations.

For collocated load and generation, the EDC should create linked queue records. The load and generation components may remain in separate administrative queues, but they should be cross-referenced, studied concurrently where technically appropriate, and subject to coordinated milestones. This avoids forcing a single integrated project through two disconnected processes in which each review assumes the other component does not exist.

In short, this framework delivers the benefits of separate queue administration without sacrificing the technical accuracy of integrated distribution system planning. Load and generation reviews should be coordinated rather than siloed and separated only where technical differences require. Whatever the procedural form, coordination is what ensures the shared distribution system is planned, and its finite capacity allocated, as the single resource it is.

Question 15: Should EDCs be required to provide hosting capacity maps?

The JCEP strongly support a hosting capacity map requirement and urge the Commission to adopt one that serves both generation and load applicants. Detailed maps materially improve the efficiency of the interconnection process for all stakeholders by giving applicants an early, location-specific indication of where capacity exists. Thereby allowing developers to direct projects toward feeders and nodes that can accommodate them and avoid circuits that cannot. The practical consequence is fewer applications filed on constrained circuits with no realistic interconnection pathway, fewer withdrawn or failed projects clogging the queue, lower study burden on the EDCs, and faster, more predictable outcomes for viable projects. And as large-load siting increasingly becomes a function of grid availability, public hosting capacity information gives load applicants the same ability to identify suitable locations, reducing speculative, scattershot applications.

This requirement is well within the established capability of the industry. Numerous EDCs already publish feeder-level hosting capacity maps for DERs, and the Commission can build on that substantial accumulated experience. Minnesota offers an instructive model: in 2020, the Minnesota Public Utilities Commission directed Xcel Energy to enhance its hosting capacity maps to include feeder-level minimum load data, transformer specifications, and voltage regulation equipment information, giving developers the granular, feeder-specific detail needed to site projects efficiently and avoid unnecessary study delays.[12]

The JCEP recognize that hosting capacity maps raise concerns regarding cybersecurity, physical security, customer confidentiality, market-sensitive information, and applicant reliance on indicative data. Those concerns should be managed through thoughtful design, not used as a basis to withhold useful information altogether. Public maps should provide enough feeder- and node-level information to support siting decisions and reduce speculative applications, while more granular or sensitive asset-level data can be provided through a secure portal, verified-applicant process, or other controlled-access mechanism.

To maximize the value of the hosting capacity map requirement and avoid shortcomings that have limited the usefulness of some existing maps in other states, the JCEP recommend that the Commission require EDCs to:

- Update the maps on a regular, defined cadence, no less than monthly, so that the information reflects current system conditions and pending queue activity rather than a stale baseline;
- Provide granularity at the feeder and node level, including substation and line-section detail, sufficient to inform siting decisions before an application is filed, and identify feeder voltage, substation locations, and related distribution assets;
- Distinguish between load-driven and generation-driven constraints, and publish supporting data on the most congested and peak-constrained portions of the system so that applicants can identify locations where limited-export, controlled-dispatch, or load-flexibility configurations could resolve a constraint;

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12 *See* In the Matter of Xcel Energy's 2019 Annual Hosting Capacity Report, Minn. Pub. Utils. Comm'n, Docket No. E002/M-19-685, *Order* (July 31, 2020) (directing Xcel Energy to supplement its hosting capacity map and downloadable data with feeder-level transformer name, transformer absolute minimum load, presence of a load tap changer or regulator, feeder absolute minimum load, feeder type, and whether daytime minimum load figures are actual or estimated).

- Show both generation hosting capacity and load-serving headroom on the same platform, reflecting the reality (discussed under Question 13) that load and DERs draw on the same feeder and substation capacity, and that an integrated view is necessary to avoid mis-stating available headroom;
- Identify known system constraints, planned upgrades, and the expected effect of those upgrades on available capacity, together with the number and size of pending applications affecting a given location, so that applicants can anticipate how capacity will evolve;
- Include functional filtering and toggling tools, an address and location search, and clear indication of the date of the underlying data;
- Disclose the assumptions, methodologies, and any operational settings (such as smart-inverter functions or assumed load profiles) underlying the hosting capacity and headroom calculations, so that results can be understood and relied upon; and
- Provide the data in a uniform, machine-readable format with consistent definitions across EDCs, so that developers and other stakeholders can perform consistent, apples-to-apples analysis statewide, and establish a clear process for applicants to flag and resolve apparent map errors.

A hosting capacity map requirement built to these specifications would improve project siting, reduce the volume of unworkable applications in both the load and generation queues, lower costs for applicants and ratepayers alike, and give the Commission and the public a far clearer picture of where Pennsylvania's distribution system can accommodate growth, and where investment is needed to enable it.

Lastly, the Commission should require EDCs to offer pre-application reports to prospective DER applicants. While hosting capacity maps offer valuable planning-level visibility, they typically reflect aggregate, feeder- or substation-level capacity rather than conditions at a specific point of interconnection. A pre-application report fills this gap by providing applicant-specific information (*e.g.*, available capacity at the exact proposed interconnection point, known upstream constraints, the impact of other applications already in the queue, etc.) that a static map cannot capture. A pre-application report allows developers to make informed decisions before fully committing to a full application, further helping to reduce the number of applications submitted to locations that may appear viable on a map but are in fact already significantly constrained. EDCs in other jurisdictions already offer this at low or no cost with a short, defined turnaround. The Commission should require EDCs to make pre-application reports available for a nominal fee with a prescribed timeframe, specifying the categories of information each report must include.

B. Accuracy in Load Assumption Inputs

Question 6: What are some methods that may be used to discourage applicants from submitting duplicative projects with different EDCs?

Question 7: In order to establish a position in the EDC's queue, would requiring a load interconnection applicant to pay a fee, based on the level of review, be effective in minimizing duplicative projects with different EDCs?

The JCEP address Questions 6 and 7 together, as both concern mechanisms, including application fees and study deposits, to discourage duplicative and speculative load interconnection requests.

The JCEP strongly support standard study deposits, project-readiness requirements, and withdrawal penalties for the interconnection of large loads. These tools would help EDCs distinguish viable projects from placeholder requests, including requests submitted to multiple utilities for the same underlying load. The Federal Energy Regulatory Commission ("FERC") recently addressed study requirements for the interconnection of large loads on the transmission system. In the order approving SPP's High Impact Large Load filing, FERC accepted heightened interconnection requirements, application fees and study deposits, for large load interconnection requests. In accepting these requirements, FERC found that study deposits reflect the estimated costs of the studies to be performed and will help discourage speculative large load interconnection requests.[13] State regulators can, and should, apply the same principle in the distribution context by requiring applicants to make an up-front commitment that is proportional to the level of review and the size and complexity of the requested service. The JCEP support study deposits that are based on net withdrawals from and, in the case of collocated facilities, injections to the grid. The Commission should consider the magnitude of requested withdrawal and injection rights of the co-location arrangement as a basis for determining the magnitude of study deposits required.

III. CONCLUSION

The Joint Clean Energy Parties commend the Commission for initiating this inquiry and for recognizing that the surge in load interconnection requests warrants a deliberate, well-designed regulatory framework. In summary, we urge the Commission to:

- Scrutinize DER interconnection with the same focus as load interconnection;
- Establish a coordinated, technology-neutral pathway for generation collocated with load, studied on a net-injection basis, fully available to solar and storage, and aligned in timing with the associated load without advancing ahead of, or delaying, the standalone generation queue;
- Require separate administrative queues for load and generation while mandating that both be modeled and evaluated against a common, integrated, and current view of distribution system capacity, without imposing a rigid, wholly standalone load queue that merely duplicates the existing generation process; and

[13] *Southwest Power Pool, Inc.*, 194 FERC ¶ 61,031 (2026).

- Require robust, frequently updated hosting capacity maps and pre-application reports that serve both load and generation applicants and disclose the data and assumptions on which they rest.

Each of these recommendations reflects the central reality that load and distributed generation share the same grid, and that rules designed for one must be coordinated with the other if Pennsylvania is to accommodate growing demand reliably and affordably. The Joint Clean Energy Parties appreciate the Commission's consideration of these comments and stand ready to provide additional detail, comparative experience from other jurisdictions, and continued engagement with the Commission and its Staff on any of the recommendations set forth above.

Respectfully submitted,

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Appendix A:

Joint Clean Energy Parties' May 15, 2026 Comments submitted to New Jersey Board of Public Utilities in Docket QO24030199

BEFORE THE NEW JERSEY BOARD OF PUBLIC UTILITIES

In the Matter of Developing Integrated Distributed Energy Resource
Plans to Modernize New Jersey's Electric Grid

Docket No. QO24030199

COMMENTS OF THE JOINT CLEAN ENERGY PARTIES

Introduction

The Coalition for Community Solar Access ("CCSA"), Advanced Energy United ("AEU"), and the Solar Energy Industries Association ("SEIA") (collectively, the "Joint Clean Energy Parties") respectfully submit these comments in response to the New Jersey Board of Public Utilities' ("Board" or "BPU") Request for Information ("RFI") regarding grid modernization and interconnection reform issued in Docket No. QO24030199.

This proceeding arrives at a critical inflection point for New Jersey's clean energy transition. The State's Energy Master Plan ("EMP"), which targets 100% clean energy by 2035, requires significant deployment of distributed energy resources ("DERs"), electrification, and grid modernization. Achieving these objectives, while simultaneously responding to the State of Emergency declared in Executive Order Nos. 1 and 2 (Sherrill, 2026) regarding affordability and load growth, will require an interconnection framework that is transparent, efficient, and capable of supporting rapid and sustained project development at scale.

While the Board has taken important steps in recent orders to improve interconnection processes, including reforms to transparency, reporting, and hosting capacity adopted in the August 13, 2025 Order, material barriers remain. These comments draw on the Joint Clean Energy Parties' experience advancing interconnection policy nationwide to present targeted recommendations for New Jersey. Collectively, they are intended to address near-term process inefficiencies while also establishing a durable, forward-looking framework capable of supporting continued DER growth across solar, energy storage, and emerging technologies such as bidirectional electric vehicle charging.

Building on this perspective, the Joint Clean Energy Parties have identified the following priority recommendations:

- Establish enforceable interconnection timelines with consequences for non-compliance;
- Expand flexible interconnection beyond current FlexIX approaches to include phased interconnection solutions;
- Improve cost certainty through cost envelopes, contingency caps, and standardized methodologies;

- Require, and continuously maintain, demonstrated site control to strengthen queue integrity;
- Advance proactive distribution system planning and multi-beneficiary cost allocation;
- Enhance hosting capacity transparency and data access;
- Clarify and improve the treatment of energy storage interconnection requests, particularly for front-of-the-meter ("FTM") storage;
- Provide clarity and transparency regarding the jurisdictional classification of 34.5 kV lines, particularly within the Jersey Central Power & Light ("JCP&L") service territory;
- Establish a Board-level interconnection ombudsperson, paired with EDC-designated internal ombudspeople;
- Modernize interconnection rules for vehicle-to-grid ("V2G") and other bidirectional charging technologies; and
- Streamline interconnection processes for residential DERs.

Enforcing Interconnection Timelines with Consequences for Non-Compliance

Timely execution of interconnection studies and construction of required upgrades is foundational to an efficient interconnection process. N.J.A.C. 14:8-5 establishes timelines for application review, screening, and study processes, including requirements applicable to Level 1 through Level 4 interconnections. These timelines must be treated as binding obligations rather than aspirational targets.

Delays in feasibility, system impact, and facilities studies, as well as delays in the construction of required upgrades, create uncertainty, increase project costs, and put at risk time-sensitive financing arrangements and federal incentives, including Investment Tax Credit ("ITC") eligibility. The Joint Clean Energy Parties therefore recommend that the Board pair its existing timeline framework with meaningful accountability mechanisms.

To address these challenges, the Board should:

- Establish corrective action requirements and accountability mechanisms, including financial penalties for nonperformance. New York's Standardized Interconnection Requirements ("SIR") provide a useful model: under the New York framework, utilities are subject to specific milestone timelines for completeness review, coordinated electric system interconnection review ("CESIR") studies, and construction, and missed milestones can trigger study-fee credits to the developer, escalating reporting obligations, and Commission-overseen remediation[1]. New Jersey should adopt an analogous structure that

[1] *See* N.Y. State Pub. Serv. Comm'n, Standardized Interconnection Requirements (current version); Case 20-E-0249, *Order Adopting Modifications to the Standardized Interconnection Requirements* (N.Y. Pub. Serv. Comm'n Apr. 15, 2021).

includes (i) per-business-day credits or refunds against study deposits and interconnection fees when an EDC misses a regulatory milestone for reasons within its control; (ii) escalation triggers (e.g., automatic notice to Board Staff and the developer when a milestone is missed by a defined threshold); and (iii) a process for the Board to direct corrective action plans for EDCs demonstrating a pattern of nonperformance.

- Expand on the existing reporting requirements established in the August 13, 2025 Order to ensure comprehensive, application-level tracking of interconnection performance, including disaggregated reporting of timeline compliance by EDC, application level (Levels 1–4), project type (solar, storage, hybrid, EV charging), and study phase, with public reporting on a quarterly basis.
- Distinguish between delays attributable to the EDC, the applicant, and exogenous factors (e.g., equipment lead times, third-party permitting), so that accountability mechanisms apply only where the EDC controls the source of delay.

Flexible and Phased Interconnection Solutions

The Board has initiated important discussions around flexible interconnection through FlexIX, including the use of advanced inverter functionality and operational flexibility. While these efforts represent meaningful progress, they are not sufficient on their own to unlock available capacity at scale. A more comprehensive framework should also include phased interconnection solutions, whereby projects can be placed in service in temporary non-export or limited-export modes until system upgrades are complete.

Such a framework should:

- Allow projects that are otherwise ready to energize to operate in a controlled, non-export or limited-export mode pending completion of system upgrades;
- Establish clear technical requirements, including curtailment parameters, telemetry, and operational controls to ensure system reliability;
- Utilize standardized agreements to provide a predictable and consistent pathway for implementation across EDCs;
- Enable projects to be placed in service while distribution system upgrades are completed, including where doing so is necessary to preserve federal Investment Tax Credit eligibility or other time-sensitive incentives; and
- Define clear, enforceable, and time-bound criteria for transitioning projects from phased operation to full export operation once required upgrades are placed in service.

Equally important to the structure of flexible interconnection is the analytical framework that EDCs use to evaluate it. To realize the full potential of flexible and phased interconnection, EDCs should be required to move beyond static, worst-case load and dispatch assumptions when modeling DER impacts. In particular, where a project is capable of operating to a defined dispatch profile, such as a bidirectional EV charger that does not export during evening peak, or a storage resource subject to controlled charge/discharge windows, the EDC's analysis should incorporate granular, time-differentiated dispatch schedules rather than assume the most adverse possible operating condition. Modeling DERs as static load (or as uncontrolled export at peak) drives unnecessary upgrade requirements, and the cost of those unnecessary upgrades is ultimately borne by interconnection customers and ratepayers. The Board should direct the EDCs to adopt time-differentiated, bidirectional-flow analytical methods, with documented assumptions, as part of the FlexIX and phased interconnection framework.

This approach complements existing FlexIX efforts and aligns with broader grid modernization objectives identified in the Board's clean energy proceedings. It enables EDCs and developers to proceed in parallel, improving timelines while maintaining system reliability.

Cost Certainty and Upgrade Cost Controls

Upgrade cost uncertainty remains a significant barrier to project development in New Jersey. Developers regularly face substantial revisions to estimated upgrade costs between study phases, and post-execution cost increases that can render otherwise viable projects uneconomic. These outcomes harm not only developers but also ratepayers, who ultimately bear the cost of stranded development effort and delayed clean-energy benefits. Compounding this dynamic, developers bear all of the financial risk of open-ended cost recovery while the EDC retains control over the factors that drive those costs—equipment selection, engineering design, procurement, and construction—creating little incentive for the EDC to keep upgrade costs reasonable and under control.

Massachusetts offers a useful model. Under the Massachusetts distributed generation interconnection tariff, where substantial system modifications are identified, utilities must advise the interconnecting customer in writing of any cost increase, but only up to a total increase of 10%, with costs above that threshold borne by the utility. In addition, customers that elect to proceed based on an Impact Study prior to completion of a Detailed Study are responsible for System Modification costs only within a ±25% band of the estimate identified in the Impact Study. The tariff also establishes a final accounting process under which the customer may request a reconciliation of estimated and actual costs and receive any refund owed within 45 business days. Massachusetts adopted this framework to provide "clear cost signals" and sufficient cost certainty to support efficient distributed generation investment while protecting ratepayers.[2] The Joint Clean Energy Parties submit that a comparable framework is well-suited to New Jersey.

[2] See Massachusetts Distributed Generation Interconnection Tariff, Interconnection Service Agreement §§ 3.3–3.4 (establishing ±25% cost-estimate band, 10% cap on customer responsibility for study-cost increases, and refund/accounting procedures); Investigation by the Department of Public Utilities on Its Own Motion into Distributed Generation Interconnection, D.P.U. 20-75, at 77–79 (Mass. Dep't of Pub. Utils. Oct. 22, 2020).

The Board should establish mechanisms to improve cost predictability, including:

- Providing cost envelopes or bounded estimates during study phases, with documented assumptions and clearly identified contingency components;
- Implementing contingency caps on cost increases between study phases and between final study and construction, beyond which cost overruns are not assignable to the interconnection customer absent a clear showing of cause;
- Standardizing cost estimation methodologies, unit costs, and contingency assumptions across EDCs through a Board-approved methodology, with periodic review; and
- Requiring transparency into the components of upgrade cost estimates so that developers can identify and, where appropriate, negotiate scope.

Together, these measures will reduce financial risk, improve project viability, align EDC incentives with prudent cost management, and support the State's near-term clean energy and affordability objectives.

Site Control and Queue Integrity

The Joint Clean Energy Parties strongly support measures to improve queue integrity. Specifically, the Board should require applicants to demonstrate site control as part of a complete interconnection application and to maintain continuous site control throughout the interconnection process. Site control is itself a meaningful cost and commitment for developers; requiring its demonstration and ongoing maintenance is an effective and proven mechanism for distinguishing serious projects from speculative or "phantom" projects.

This reform would:

- Improve alignment between queue position and project readiness;
- Reduce unnecessary strain on EDC study resources caused by speculative applications;
- Increase overall efficiency of the interconnection process; and
- Make capacity available sooner to projects that are genuinely ready to develop.

At the same time, the Board should be careful in how broader "project readiness" requirements are designed. Recent experience in other jurisdictions, including New York, illustrates that overly aggressive milestone or readiness requirements can disqualify legitimate, actively developing projects whose progress is delayed by factors outside the developer's control, such as local permitting timelines, environmental review, or equipment lead times. The Joint Clean Energy Parties therefore recommend that the Board:

- Adopt site control as the foundational queue-integrity requirement, both at application and on a continuing basis;

- Establish a defined mechanism by which inactive projects that have failed to demonstrate continued progress beyond a clearly stated threshold lose their queue position, so that capacity is not held indefinitely by speculative or abandoned applications;
- Permit applicants to demonstrate ongoing development progress through reasonable, flexible indicators (e.g., evidence of permit applications filed, interconnection deposits paid, equipment procurement initiated, off-take or financing arrangements pursued) rather than rigid pass/fail milestones tied to dates outside the developer's control;
- Provide a defined cure or notice period before any project is removed from the queue for failure to demonstrate progress; and
- Distinguish between active development delays and project abandonment, recognizing that exogenous factors are an inherent feature of distributed generation development.

This calibrated approach preserves the queue-integrity benefits of site control and progress requirements while avoiding the harm caused by mechanically penalizing legitimate projects.

Proactive Distribution System Planning and Cost Allocation

The Board has recognized the importance of grid modernization and proactive planning in advancing the State's clean energy objectives. Building on these efforts, New Jersey should continue to move toward a more proactive distribution system planning framework that anticipates DER growth and electrification load rather than responding to them on a project-by-project basis.

This includes:

- Identifying constrained circuits and high-value upgrade opportunities through structured, transparent planning processes that incorporate DER deployment forecasts and load growth scenarios;
- Coordinating distribution planning with broader DER deployment, electrification, and beneficial-load forecasts so that upgrades are scoped to support multiple incoming projects rather than only the next interconnection customer;
- Exploring multi-beneficiary cost allocation approaches that fairly apportion the cost of system upgrades among the projects, ratepayers, and other beneficiaries that derive value from them; and
- Aligning planned upgrades with the constrained-circuit identifications requested in this RFI so that capital deployment is directed where it produces the greatest interconnection and reliability benefit.
- Require EDCs to provide PJM with reasonably accurate forecasts of installed capacity and commercial operation date timelines for the full range of DER market segments, including behind-the-meter solar and storage, front-of-the-meter solar, and front-of-the-meter (FTM) distribution-connected storage. Ensuring that PJM receives complete and accurate DER forecasts, including FTM storage, is essential if these resources are to exert their anticipated

downward pressure on capacity prices, and to ensure that PJM's load and resource adequacy modeling reflects the resources New Jersey is actively bringing online. This forecasting function should be integrated into, and informed by, the broader distribution system planning process described above, so that EDC submissions to PJM are grounded in the same DER deployment and interconnection queue data used for distribution planning.

Such reforms will reduce reliance on reactive, project-specific upgrades, lower aggregate cost to ratepayers, improve long-term system efficiency, and ensure that the capacity benefits of New Jersey's DER deployment are fully reflected in PJM's markets.

Hosting Capacity Transparency and Data Access

The Board has already taken important steps to improve transparency, including the enhanced interconnection reporting and hosting capacity update requirements established in the August 13, 2025 Order. These efforts should be expanded to further improve usability and effectiveness.

The Board should require EDCs to:

- Increase the frequency and timeliness of hosting capacity map updates, including verification that monthly updates are being completed in practice;
- Provide greater granularity at the circuit and node level, sufficient to inform site selection decisions before an application is filed;
- Distinguish on the maps between load-driven constraints and generation-driven constraints, and publish supporting data on the most congested and peak-constrained portions of the distribution system, including local system peaks, areas of identified grid congestion, and anticipated load growth. This combined view allows developers and EDCs to identify locations where limited-export or controlled-dispatch configurations could resolve a constraint and avoid blanket "no" responses where a tailored operating regime would preserve local reliability, and is particularly valuable for siting energy storage and other dispatchable DERs whose value depends on the load-side profile of the local system rather than available generation headroom;
- Include information on identified system constraints, planned upgrades, and the expected impact of those upgrades on hosting capacity;
- Provide a uniform, machine-readable data format and consistent definitions across the four EDCs to enable apples-to-apples analysis; and
- Disclose the assumptions, methodologies, and any operational settings (such as smart inverter functions) underlying hosting capacity calculations.

Enhanced transparency will improve project siting, reduce the volume of applications filed on circuits with no realistic interconnection pathway, and improve the efficiency of the interconnection process for both developers and EDCs.

Treatment of Energy Storage System Interconnection Applications

The Joint Clean Energy Parties have closely reviewed the EDCs' responses to Question E.1 of the RFI regarding the analysis and interconnection of energy storage systems ("ESS"). The responses are, in our view, notably vague regarding how the EDCs are processing storage interconnection requests, and in particular how they are treating FTM storage projects.

Based on the experience of our member companies, it is our understanding that the EDCs are generally not studying FTM storage projects under the current process. That conclusion is not readily apparent from the EDCs' written responses, and the Joint Clean Energy Parties believe it is important that the Board be made aware of this practical reality. Nothing in N.J.A.C. 14:8-5 exempts FTM storage from the interconnection process or conditions the processing of such applications on the existence of a finalized storage compensation program. The current practice appears to be driven by the absence of an operational program-side mechanism (such as a settled storage compensation framework) rather than by any limitation in the interconnection rules themselves, and the Joint Clean Energy Parties submit that this is not a lawful basis for declining to process FTM storage applications.

To address this, the Board should:

- Direct each EDC to clearly state, on the record, whether and under what conditions it is currently studying and processing FTM storage interconnection requests, and to identify specifically any storage application categories it is not currently processing;
- Confirm that the absence of a finalized storage compensation program is not a lawful basis for declining to process or interconnect FTM storage applications, and that EDCs are obligated to process such applications under the existing interconnection framework;
- Direct EDCs to begin actively studying and processing FTM storage applications now, in advance of any future program launch. Doing so will avoid a predictable bottleneck in which EDCs and developers must simultaneously address a wave of applications and a new programmatic framework, and will instead allow the EDCs to develop process maturity, study templates, and operational familiarity with FTM storage before program-driven volume materializes;
- Ensure that interconnection processing of storage projects is decoupled from the development status of any particular storage compensation program, so that interconnection readiness is not held hostage to programmatic timing; and
- Adopt clear technical and procedural standards for storage applications that recognize the distinct characteristics of storage as compared with generation-only resources (including charging behavior, export-limiting capabilities, and hybrid configurations).

Jurisdictional Treatment of 34.5 kV Lines

Question C.2 of the RFI specifically asks each EDC to identify whether its territory includes 34.5 kV lines and whether those lines are treated as distribution or transmission. The Joint Clean Energy Parties have reviewed the responses with particular interest, given that 34.5 kV lines often represent a significant share of available hosting capacity—especially for community solar and other mid-sized DER projects.

JCP&L's response continues a pattern that the Joint Clean Energy Parties find troubling. JCP&L generally asserts that most or all of its 34.5 kV lines are FERC-jurisdictional transmission, and on that basis treats those lines as off-limits for distribution-level interconnection under N.J.A.C. 14:8-5 but does not provide clear justification or evidence of FERC jurisdiction. It is our understanding that at least in some cases JCP&L bills retail customers served from 34.5 kV facilities under its distribution tariff. This potential inconsistency, distribution treatment for retail billing, transmission treatment for interconnection, deserves Board scrutiny, particularly because the practical consequence is to foreclose substantial hosting capacity that is otherwise available in JCP&L territory but not in the territories of the other New Jersey EDCs, all of whom permit interconnection at 34.5 kV under the Board's rules.

The Joint Clean Energy Parties therefore request that the Board:

- Direct JCP&L to provide detailed maps designating, on a line-by-line basis, which 34.5 kV facilities the company classifies as distribution and which it classifies as transmission;
- Direct JCP&L to provide a specific, facility-level justification for each transmission designation, including the operational and contractual basis on which the company relies and the consistency of that designation with the company's retail tariff treatment of the same facilities;
- Compare JCP&L's approach with that of Atlantic City Electric, Public Service Electric & Gas, and Rockland Electric Company, all of which interconnect DERs to 34.5 kV distribution facilities; and
- Make clear that, where 34.5 kV lines are functioning as distribution facilities under New Jersey law, they are subject to N.J.A.C. 14:8-5 and must be made available for DER interconnection on the same terms as other distribution facilities.

Resolving this issue would unlock meaningful hosting capacity for community solar and other DERs in JCP&L territory and is directly responsive to the Board's focus in this RFI on 34.5 kV interconnection access.

Establishment of an Interconnection Ombudsperson

To improve accountability and facilitate dispute resolution, the Board should establish an interconnection ombudsperson at the Board, and should require each EDC to designate an internal interconnection ombudsperson as well. A two-sided ombudsperson structure ensures developers have both an independent escalation path at the Board and a clearly identified, accountable EDC counterpart empowered to resolve issues within the company. This dual structure provides a lower-cost alternative to formal complaint proceedings and helps surface systemic issues earlier.

The Board-level interconnection ombudsperson should:

- Serve as a neutral, independent point of contact for developers and EDCs;
- Facilitate informal resolution of interconnection disputes, including disputes over study results, upgrade cost estimates, timeline compliance, and queue position;
- Identify systemic issues and recommend improvements to the Board on a periodic basis; and
- Publish anonymized aggregate information regarding the types and resolution of disputes, to inform ongoing Board oversight.

Each EDC should, in parallel, designate an internal interconnection ombudsperson with the authority and accountability to:

- Receive and triage developer concerns regarding specific applications, study results, or process compliance;
- Coordinate cross-functionally within the EDC to obtain prompt, substantive responses; and
- Serve as the EDC's primary point of contact for the Board-level ombudsperson on systemic issues.

This two-sided approach is consistent with best practices in other jurisdictions and would meaningfully strengthen the Board's oversight of interconnection processes.

Modernizing Interconnection Rules for Vehicle-to-Grid and Bidirectional Charging Systems

There is a growing need to address bidirectional charging systems and their unique operating use cases within the Board's DER interconnection rules. Greater clarity in how to process and review applications for these systems, whether operating in parallel with the grid, or in non-parallel modes such as isolated backup or charge-only, will benefit both customers and utility engineers.

More electric vehicles ("EVs") are being produced with bidirectional capabilities each year. The vast majority of customers who purchase a vehicle with bidirectional features will simply charge their vehicle and never export to the grid. Inadvertently capturing every such EV owner within the interconnection process based on a vehicle's theoretical "capability" rather than its intended use case would impose substantial unnecessary burden and risks discouraging EV adoption in New Jersey.

As the interconnection rules are updated to incorporate the most recent standards relevant to V2G operation (including UL 1741 and IEEE 1547), it is also important to avoid locking in specific versions of those standards. New Jersey has thus far avoided this issue by not specifying a particular version of UL 1741, and that flexibility should be preserved.

Vehicle batteries in particular can face outsized impact study requirements when battery nameplate energy is treated as the basis for review rather than the inverter capability. The relevant grid impacts of any DER, including a vehicle operating in V2G mode, are governed by the inverter's output limits (often less than 15 kW) rather than the underlying battery capacity (often greater than 100 kWh). Because EV batteries are necessarily orders of magnitude larger than residential stationary storage given their dual-use design, customers should not be penalized in the interconnection process for that capacity.

To address these challenges, the Board should:

- Focus interconnection rules around the configured use case of bidirectional systems (e.g., charge-only, isolated backup, parallel export) rather than around theoretical maximum capability;
- Maintain flexibility on key standards by referencing the applicable standard family (e.g., UL 1741, IEEE 1547) rather than specific edition years, and allow deviations or updates as new versions are released and adopted;
- Use inverter capacity, not battery nameplate energy, as the basis for determining the applicable interconnection review level for EVs and other inverter-coupled storage resources; and
- Coordinate the interconnection rules with the Board's broader work on EV charging, vehicle-grid integration, and any complementary virtual power plant or distributed flexibility programs.

Streamline Interconnection Processes for Residential DERs

The Board's recent updates to NJAC 14:8-5 are a significant improvement to interconnection rules for BTM residential resources that are already facilitating more efficient and economical system deployment across the state. To fully capitalize on these improvements, the EDCs should examine their current submission processes and make the following targeted improvements.

The EDCs should evaluate expansion projects (adding storage or additional PV capacity to a home with existing PV) on the incremental capacity of the added equipment rather than the total capacity at a site. Requiring the evaluation of updated total capacity, rather than the impact of incrementally added capacity, is requiring redundant work on already-studied capacity as well as duplicative fees and unnecessary rejections. The existing system is already accounted for in the EDCs' capacity mapping, and evaluating expansions on their own would align New Jersey utilities with national best practices.

Additionally, all NJ EDCs should make their controlled-export offerings easily accessible. Requiring customers to re-apply as a limited export system when projects cannot connect at full export capacity on constrained circuits adds unnecessary barriers to bringing more clean capacity online. JCP&L and PSE&G allow revisions to existing submissions whereas ACE outright denies applications, forcing reapplication with the associated customer friction and duplicative fees.

Lastly, all NJ EDCs should do away with outmoded and duplicative submission processes. While JCP&L and Rockland Electric utilize online portals and e-signatures, other EDCs are still forcing customers to submit hand-signed documents. ACE even requires an identical paper application with the same information submitted through their portal. While we can appreciate that different internal systems have unique constraints, NJ EDCs should bring their interconnection application processes into the 21st century as they modernize the rest of their business practices.

Conclusion

The recommendations set forth above are intended to provide the Board with a practical, durable framework for advancing interconnection reform in New Jersey. In summary, the Joint Clean Energy Parties urge the Board to: (1) establish enforceable interconnection timelines paired with meaningful consequences for non-compliance, drawing on the New York SIR model; (2) expand flexible interconnection to include phased operation pending upgrade completion; (3) deliver cost certainty through cost envelopes, contingency caps, and standardized methodologies; (4) strengthen queue integrity through site control while preserving room for legitimate development delays; (5) advance proactive distribution planning and multi-beneficiary cost allocation; (6) deepen hosting capacity transparency; (7) clarify EDC treatment of FTM energy storage and bring practice into alignment with N.J.A.C. 14:8-5.2(m); (8) require JCP&L to substantiate and document its jurisdictional treatment of 34.5 kV lines; (9) establish a Board-level interconnection ombudsperson and require each EDC to designate an internal counterpart; (10) modernize the rules for V2G and bidirectional charging systems; and (11) streamline interconnection processes for residential DERs.

Expedient action on these recommendations is essential. New Jersey is operating against the dual pressures of a declared State of Emergency on energy affordability and an Energy Master Plan target of 100% clean energy by 2035. Each month of avoidable interconnection delay translates directly into deferred clean energy generation, lost ratepayer savings, and missed opportunities to bring affordable, in-state resources online at the moment they are most needed. The reforms recommended here are not abstract—they are practical, drawn from working models in other jurisdictions, and capable of producing measurable improvements within the existing regulatory framework.

The Joint Clean Energy Parties commend the Board for opening this proceeding and for the substantial progress already reflected in the August 13, 2025 Order and the Board's broader grid modernization work. The issuance of this RFI, in direct response to Executive Order No. 2, demonstrates the Board's continued leadership in confronting the interconnection challenges that stand between New Jersey and its clean energy goals.

The Joint Clean Energy Parties stand ready, willing, and eager to engage further with the Board and Board Staff on any of the recommendations set forth above. We welcome the opportunity to provide additional detail, share comparative experience from other jurisdictions, and work collaboratively with the Board, the EDCs, and other stakeholders to design and implement reforms that are both ambitious and workable. We thank the Board for its consideration of these comments.

Respectfully submitted,

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