Comments on Interconnection Regulation

Core Components, Concepts, and Key Questions

Case No. NER-MI-2019-0009

Submitted by:

Solar and Energy Storage Association of Puerto Rico (SESA)

April 15, 2026

Executive Summary

About SESA

The Solar and Energy Storage Association of Puerto Rico (SESA) is a trade association representing solar installers, equipment manufacturers, project developers, and other companies in Puerto Rico's solar and energy storage industry. SESA has been an active participant in this interconnection rulemaking docket since 2019.

History Leading to Joint Resolution 193

Puerto Rico's current interconnection regulations (8915 and 8916) were adopted in February 2017 under Act 114-2007. In April 2019, Law 17-2019 created a series of new requirements, including automatic interconnection for systems up to 25 kW and a maximum 90-day approval timeline for systems above 25kW, and required new regulations within 180 days. That deadline was not met. Despite workshops (2019), a preliminary draft rule (2021), and LUMA's proposed TIR (2022), no new regulation was adopted.

On January 7, 2026, Governor González Colón signed Joint Resolution 193 (RCC 193), ordering cessation of certain charges and establishing a firm one-year timeline to complete the rulemaking. As signed, RCC 193 is officially designated as "Joint Resolution 5-2026" (hereinafter, "Joint Resolution 5-2026" or "JR 5-2026").

Requirements of Joint Resolution 5-2026

JR 5-2026 mandates: (1) cessation of all Supplemental Study and grid improvement charges for PV systems up to 25 kW; (2) nullification of conflicting provisions of Regulation 8915; (3) expert-facilitated participatory workshops; (4) adoption of modern interconnection concepts including proactive hosting capacity planning, meter socket adapters, daytime minimum load, curtailment compensation, and grid study cost treatment; (5) a draft regulation by July 7, 2026; and (6) final adoption by January 7, 2027.

SESA's Key Areas of Input

The remainder of this document provides initial input on the following areas, which we hope are useful to the Energy Bureau in the development of this important new rule:

A. Legal Requirements of Law 17-2019
B. Legal Requirements of Joint Resolution 5-2026
C. Responses to PREB's March 19, 2026 Order
D. Input on Format of Document for New Interconnection Rule

I. Introduction

The Solar and Energy Storage Association of Puerto Rico ("SESA") respectfully submits these comments to the Puerto Rico Energy Bureau ("Energy Bureau" or "PREB") in response to the Resolution and Order issued on March 19, 2026, in consolidated Case Nos. NEPR-MI-2019-0009 and CEPR-MI-2018-0008 (the "March 19 Order").

SESA is a trade association representing companies in Puerto Rico's solar energy and energy storage industry. SESA's members include residential and commercial solar installers, inverter and equipment manufacturers, battery storage providers, project developers, and financial service companies that together serve tens of thousands of customers across Puerto Rico. SESA's mission is to advance the adoption of solar energy and energy storage in Puerto Rico through sound public policy, fair regulatory frameworks, and an interconnection process that is modern, efficient, and aligned with the island's energy public policy goals.

SESA has been a consistent and active participant in this interconnection rulemaking docket since the Energy Bureau first opened Case No. NEPR-MI-2019-0009 in May 2019. SESA participated in the Bureau's interconnection workshops in the summer of 2019, submitted detailed written comments on the Bureau's preliminary draft interconnection regulation in 2021, provided extensive comments and a redline of LUMA's proposed Technical Interconnection Requirements (TIR) document in December 2022, and has continued to engage with regulators, legislators, and other stakeholders throughout this process. SESA has been actively preparing for this rulemaking proceeding since the signing of Joint Resolution 193 in January 2026.

II. Background and History of the Interconnection Rulemaking

A. Original Interconnection Regulations (2017)

The foundation of Puerto Rico's current interconnection framework dates to Act 114-2007, which established the legal authority for interconnection of distributed generators and participation in net metering programs. Pursuant to this Act, the Puerto Rico Electric Power Authority ("PREPA") adopted two interconnection regulations in February 2017:

- **PREPA Regulation 8915** – *Regulation for Interconnecting Generators with the Electric Distribution System of the Power Authority and Participating in Net Metering Programs* (February 6, 2017). This regulation governs the interconnection of distributed generators to the distribution system and establishes the processes for participating in net metering.

- **PREPA Regulation 8916** – *Regulation for Interconnecting Generators to the Transmission and Sub-Transmission System*. This regulation addresses larger generation facilities connecting at the transmission and sub-transmission level.

These regulations established the procedural and technical framework for interconnecting distributed generation systems in Puerto Rico. However, even at the time of their adoption, stakeholders noted that the regulations did not fully reflect modern interconnection practices and contained provisions that could create unnecessary barriers, particularly for smaller residential systems.

B. Law 17-2019: The Puerto Rico Energy Public Policy Act

On April 11, 2019, the Legislature enacted Law 17-2019, known as the Puerto Rico Energy Public Policy Act. This landmark legislation introduced sweeping changes to Puerto Rico's energy policy, including provisions with direct and significant impact on interconnection regulation:

- **Section 9 – Public Policy on Interconnection:** Established that it is the public policy of Puerto Rico to ensure that interconnection procedures are effective in terms of cost and processing time, in order to promote distributed generation and incentivize economic activity. Mandated that interconnection procedures use FERC's Small Generator Interconnection Procedures (SGIP) and Small Generator Interconnection Agreement (SGIA) as a model. Required expedited processes for systems under 1 MW and that procedures be uniform across all regions.

- **Automatic Interconnection for Systems ≤25 kW**: Law 17-2019 established that photovoltaic or renewable energy systems registered in the renewables registry whose generation capacity does not exceed 25 kilowatts shall be interconnected automatically to the transmission and distribution network upon certification by a qualified engineer or electrician. No interconnection application is required for these systems. Net metering must be reflected in the customer's monthly bill within 30 days of the utility's receipt of certification that the system has been installed incompliance with current any applicable interconnection requirements. Furthermore, if a feeder exceeds its capacity, that fact "shall not constitute an obstacle for interconnection of these systems".

- **Section 10 – Rulemaking Authority:** Directed PREPA to adopt or modify regulations within 180 days of Law 17's promulgation (by approximately October 2019). Required separate regulations for systems under 1 MW and for systems between 1 MW and 5 MW. In the event PREPA failed to adopt new regulations within the 180-day period, the evaluation and approval process for interconnection would be established by the Energy Bureau, following best practices of the industry, with the purpose of reducing administrative steps while safeguarding grid reliability and safety. The Bureau is required to hold public hearings prior to approving any amendments to interconnection regulations, with hearings held no less than 30 days after publication of notice.

- **90-Day Review Period:** For systems above 25kW in size, which are not subject to "automatic interconnection", Law 17-2019 requires that the evaluation of interconnection applications shall not exceed 90 days from filing. If the utility fails to act within this period, the application is automatically approved, although in that case the utility may later provide grounds for requirements and/or improvements.

C. The Interconnection Rulemaking Process (2019–2025)

Following the enactment of Law 17-2019, the Energy Bureau initiated the interconnection rulemaking process. What followed was a protracted series of steps that, despite significant stakeholder engagement, did not result in the adoption of a new regulation. The key milestones are as follows:

1. Energy Bureau Opens the Proceeding (May 2019)

On May 20, 2019, within weeks of passage of Law 17-2019, the Energy Bureau issued a Resolution and Order opening Case No. NEPR-MI-2019-0009 to address the process of modifying current interconnection regulations and aligning them with Law 17-2019.

2. PREB Interconnection Workshops (Summer 2019)

In June and July 2019, the Energy Bureau conducted interconnection workshops and invited stakeholder feedback. SESA, the Independent Consumer Protection Office (OIPC, for its Spanish acronym), Sunrun, and PREPA submitted written comments. Stakeholders broadly supported modernization and streamlining of the interconnection process, with emphasis on enforcing Law 17-2019's automatic interconnection for systems up to 25 kW, establishing strict timelines with enforcement mechanisms, and proactive hosting capacity planning by the utility.

3. PREPA Fails to Produce a Draft Regulation

Despite Law 17-2019's mandate that PREPA promulgate new interconnection regulations within 180 days (by approximately October 2019), PREPA did not produce a draft regulation. This failure triggered the statutory fallback provision in Section 10 of Law 17-2019, which provides that if PREPA fails to act, the Energy Bureau shall establish the interconnection evaluation and approval process.

4. PREPA Issues Technical Memoranda

In the absence of a comprehensive new regulation, PREPA issued two technical memoranda ("Comunicados Técnicos") addressing interconnection-related matters:

- **Comunicado Técnico 19-02 (2019)** – Addressed technical requirements for interconnection of distributed generators.

- **Comunicado Técnico 20-01 (2020)** – Addressed net metering-related technical and procedural requirements.

While these technical memoranda provided some important interim guidance, which is still in use as of today, they did not constitute the comprehensive regulatory reform required by Law 17-2019 and did not go through a formal rulemaking process with stakeholder participation.

5. PREB Publishes a Preliminary Draft Rule (July 2021)

On July 15, 2021, the Energy Bureau issued a Resolution and Order that consolidated Case Nos. NEPR-MI-2019-0009 and CEPR-MI-2018-0008, as both cases pertained to interconnection of electrical systems to the electric power grid. As an attachment to this

Resolution, the Bureau published a preliminary draft for a new comprehensive interconnection regulation governing the interconnection of distributed generators and microgrids. The Bureau established a deadline of July 30, 2021 for stakeholders to submit comments on the preliminary draft.

Multiple stakeholders submitted detailed comments, including SESA, the OIPC, and LUMA. SESA's comments emphasized: (a) the need for the regulation to faithfully implement Law 17-2019's automatic interconnection for systems up to 25 kW using a "notification" rather than "application" model; (b) proactive hosting capacity planning rather than managing capacity constraints through supplemental studies and queues; (c) strict timelines with automatic enforcement; and (d) a collaborative, multi-step rulemaking process with facilitated stakeholder workshops rather than one-shot written filings.

6. LUMA Proposes a Separate Technical Document (November 2021)

On November 15, 2021, LUMA filed a Motion to Submit Additional Comments, proposing that detailed technical interconnection requirements be removed from the preliminary draft regulation and placed in a separate document—the Technical Interconnection Requirements ("TIR"). LUMA presented a Preliminary Draft TIR for review and approval by the Energy Bureau.

7. PREB Asks for Stakeholders Comment on TIR (2022)

On September 9, 2022, the Energy Bureau granted LUMA until October 7, 2022 to file additional comments on distributed generation subjects, and invited all stakeholders to provide feedback on LUMA's TIR. The comment deadline was extended to December 1, 2022.

SESA filed extensive comments and a detailed redline of the proposed TIR in December 2022. Among other things, SESA called for: eliminating or substantially raising the outdated "15%" threshold that triggered supplemental studies; incorporating Law 17-2019's expedited pathway for systems at or below 25 kW; modernizing smart inverter settings to reflect current IEEE and UL standards; and conducting professionally facilitated, multi-step stakeholder workshops rather than relying solely on written comment rounds. The OIPC also submitted comments cautioning against premature adoption of full IEEE 1547-2018 compliance requirements given the current state of grid monitoring and automation in Puerto Rico.

8. Legislative Action: RCC 604 is Pocket Vetoed

Prior to RCC 193, in 2024 the Legislature passed a substantially similar measure—R. C. de la C. 604 (RCC 604)—which was pocket vetoed by then-Governor Pedro Pierluisi. RCC 604 would have ordered PREPA and/or LUMA to permanently cease collecting all Supplemental Study charges under Regulation 8915 for customers with photovoltaic systems up to 25 kW who had notified LUMA of their interconnection on or before October 1, 2024. For systems

notified after that date, RCC 604 would have reduced the Supplemental Study charge to $250 (paid at the time of interconnection notification, together with the existing $100 fee, for a total of $350). RCC 604 also would have directed the Energy Bureau to resume the rulemaking process within 45 days and complete a draft proposed regulation within 120 days, with the full regulatory process concluded within 360 days. While RCC 604 did not become law, its passage by the Legislature demonstrated the broad legislative consensus that the interconnection charges under Regulation 8915 were inconsistent with Law 17-2019 and that the prolonged rulemaking delay required legislative intervention. RCC 193, signed into law the following legislative session as Joint Resolution 5-2026, went further than RCC 604 by eliminating Supplemental Study charges entirely for systems up to 25 kW (rather than merely reducing them) and by incorporating additional modern interconnection concepts.

9. Joint Resolution 193 is Signed into Law as Joint Resolution 5-2026 (January 7, 2026)

On January 7, 2026, Governor Jenniffer González Colón signed Joint Resolution 193 (R. C. de la C. 193, or "RCC 193"), officially designated as Joint Resolution 5-2026, as mentioned. This legislation directly addressed the prolonged failure to complete the interconnection rulemaking and the continued charging of fees that conflict with Law 17-2019. The signing of JR 5-2026 represented a decisive legislative intervention after years of regulatory stall. Joint Resolution 5-2026 went further than RCC 604 by eliminating Supplemental Study charges entirely for systems up to 25 kW (rather than merely reducing them) and by incorporating additional modern interconnection concepts.

10. PREB Issues March 19, 2026 Resolution and Order

On March 19, 2026, in response to JR 5-2026, the Energy Bureau issued a Resolution and Order resuming the administrative processes in this case. The Bureau identified seven unresolved issues for stakeholder input, invited comments on the TIR and Smart Inverter Settings (noting an ongoing NREL study), and established April 15, 2026 as the deadline for initial stakeholder comments. The Bureau indicated it would subsequently schedule stakeholder workshops to discuss the comments and inform modifications to the preliminary draft regulation. The Bureau confirmed the statutory deadlines: a draft proposed interconnection regulation by July 7, 2026, and completion of the regulatory process by January 7, 2027.

III. Requirements of Joint Resolution 5-2026

Joint Resolution 5-2026 establishes several specific mandates that shape the scope, timeline, and required content of the new interconnection regulation. SESA sets forth these requirements here so that all participants in this proceeding have a clear understanding of the legislative directives that must be satisfied.

A. Cessation of Charges for Systems Up to 25 kW

Section 1 of JR 5-2026 orders PREPA and/or LUMA to:

- Cease notifying and collecting any Supplemental Study and grid improvement fees required by Regulation 8915, including but not limited to the charges set forth in Section V, Article B of Regulation 8915, for customers with photovoltaic systems up to 25 kW who notified LUMA of their interconnection prior to the effective date of the Resolution.

- Charge no Supplemental Study fee for any photovoltaic system whose generation capacity is less than or equal to 25 kW.

- Any provision of Regulation 8915 inconsistent with these directives is rendered null and void.

B. Resumption of Rulemaking with Expert Facilitation

Section 2 of JR 5-2026 directs the Energy Bureau to resume the administrative processes in consolidated cases NEPR-MI-2019-0009 and CEPR-MI-2018-0008 and to conduct participatory workshops with interested entities. Critically, the Resolution specifies that these workshops must be:

- **Guided by a recognized expert:** The workshops must be led by "a firm or entity recognized for its high expertise and substantial previous proven experience in moderation of intensive and multi-participatory processes of interconnection regulation."

- **Inclusive:** The expert-led workshops will consider new inputs and feedback from various stakeholders.

- **Productive:** The workshops will conclude with the preparation of a draft proposed interconnection regulation, which will be subject to the formal regulatory process under the Uniform Administrative Procedure Act (Law 38-2017).

C. Modern Interconnection Technologies and Concepts

Section 2 of JR 5-2025 specifies that the new regulation must adopt modern interconnection technologies and concepts, explicitly including:

1. Proactive hosting capacity planning and budgeting
2. Meter socket adapters
3. Daytime minimum load
4. Compensation for economic losses to customers who suffer export restrictions (curtailment) associated with the imposition of configurations on inverters
5. Costs of the transmission and distribution system operator for network studies

The Resolution uses the phrase "among others," indicating that this is a non-exhaustive list and that the regulation may address additional modern concepts as appropriate.

D. Cost Allocation Principles

JR 5-2026 establishes that the costs related to modifications or improvements that may be required shall be determined in accordance with the principles of reasonableness, proportionality, and benefit received, preventing such costs from being unfairly transferred to all customers of the electricity system. The methodology for cost distribution shall be established by the Energy Bureau by regulation.

E. Timeline Requirements

JR 5-2026 imposes two firm deadlines, measured from January 7, 2026 (the date of approval):

- 180 days (approximately July 7, 2026): The process leading to the preparation of a draft proposed interconnection regulation shall be concluded.

- 365 days (January 7, 2027): The Energy Bureau, with the assistance of the recognized expert facilitator and the active participation of interested parties, will finalize the regulatory process for the adoption of a new Interconnection Regulation.

IV. SESA Initial Input

A. Legal Requirements of Law 17-2019

As discussed in detail in Section II.B above, Law 17-2019 established several binding legal requirements that the new interconnection regulation must satisfy. SESA highlights the following provisions that are most critical to get right in this rulemaking:

- **Automatic interconnection for systems ≤25 kW (Section 9):** Systems whose generation capacity does not exceed 25 kW shall be interconnected automatically upon certification by a qualified professional. No interconnection application is required. Net metering must be activated within 30 days of receiving a registration. Feeder capacity constraints shall not constitute an obstacle.

- **90-day maximum review for systems >25 kW (Section 9):** The utility's evaluation of interconnection applications shall not exceed 90 calendar days. If the utility fails to act within this period, the application is automatically approved by operation of law.

- **FERC SGIP as the model (Section 9):** Interconnection procedures must use FERC's Small Generator Interconnection Procedures (SGIP) and Small Generator Interconnection Agreement (SGIA) as a model, and must be uniform across all regions.

- **Rulemaking authority defaults to PREB (Section 10):** Because PREPA failed to promulgate regulations within the 180-day statutory period, the evaluation and approval process for interconnection is to be established by the Energy Bureau, following best practices of the industry, with the purpose of reducing administrative steps while safeguarding grid reliability and safety.

- **Public hearings required (Section 10):** The Bureau must hold public hearings prior to approving any amendments to interconnection regulations. Such hearings shall not be held within less than 30 days after publication of notice. The Bureau must issue its determination within 30 days after the public hearing process has concluded.

- **Technology-neutral scope:** Law 17-2019 references "distributed generators" broadly, consistent with FERC's SGIP, which applies to all generation technologies—not only solar and batteries, but also wind, combined heat and power ("CHP"), fuel cells, and other distributed energy resources.

B. Legal Requirements of Joint Resolution 5 of 2026

The specific mandates of Joint Resolution 5-2026 are set forth in detail in Section III above. In this subsection, SESA provides its input on the implementation of each JR 5-2026 requirement.

1. End All Supplemental Study and Grid Improvement Charges for Systems Up to 25 kW

JR 5-2026 is clear and unambiguous: no Supplemental Study fee shall be charged for any photovoltaic system whose generation capacity is less than or equal to 25 kW, and any provision of Regulation 8915 inconsistent with this directive is null and void. To SESA's knowledge, LUMA has ceased charging the $300 Supplemental Study fees and has thus been in compliance with this requirement in practice. The new interconnection regulation developed through this proceeding must codify this prohibition . Specifically, Section V, Article B of Regulation 8915—which established the $300 Supplemental Study fee structure—must be formally repealed and replaced with language consistent with JR 5-2026.

2. Repeal Conflicting Provisions of Regulation 8915

JR 5-2026renders null and void any provision of Regulation 8915 inconsistent with the prohibition on Supplemental Study charges for systems up to 25 kW. Beyond Section V, Article B, the new regulation should review and identify all provisions of Regulation 8915 that conflict with either JR 5-2026 or Law 17-2019, and ensure they are repealed or amended accordingly. The new regulation cannot include any provision that conditions interconnection of systems up to 25 kW on the completion of supplemental studies, payment of study-related fees, or utility approval of grid improvements.

3. Proactive Hosting Capacity Planning and Budgeting

JR 5-2026 specifically requires the new regulation to adopt proactive hosting capacity planning and budgeting. This represents a fundamental paradigm shift from the current reactive approach—where the utility is effectively "surprised" each time a new customer interconnects solar—to a forward-looking model where the utility plans and budgets for the distributed generation growth that is already occurring and will continue.

Proactive hosting capacity planning involves the systematic assessment of each circuit's ability to accommodate distributed energy resources, along with planned infrastructure investments to expand that capacity over time. Several U.S. utilities and state regulators have implemented hosting capacity planning programs:

- **California (PG&E, SCE, SDG&E):** California's investor-owned utilities have implemented Integration Capacity Analysis (ICA) incorporated into their Rule 21 interconnection procedures. Public data portals with geospatial mapping show available grid capacity at each location, enabling streamlined interconnection and reducing project wait times.

- **New York (Con Edison):** Con Edison publishes bi-annually updated hosting capacity maps with sub-feeder-level analysis, showing available DER capacity by feeder. The maps are updated monthly for larger projects (>500 kW), providing near-real-time

visibility into grid capacity.

- **Illinois (ComEd):** ComEd publishes near-real-time hosting capacity maps with monthly data updates for all distribution circuits at 34 kV and below, providing the latest grid availability information to developers and customers.

As of 2024, 58 utilities across 26 states plus the District of Columbia have published hosting capacity maps, demonstrating that this is now standard practice in the U.S. electric utility industry.

SESA's recommendation: Given the complexity and scope of implementing a full proactive hosting capacity planning and budgeting process—which requires detailed circuit-by-circuit analysis, long-term demand and DER growth forecasting, and capital planning—SESA questions whether it is realistic to complete this entire process within the confines of this interconnection rulemaking.

Instead, SESA recommends that this new interconnection regulation establish a firm requirement that a proactive hosting capacity planning and budgeting process be completed within a reasonable timeframe of the rule's effective date, with the regulation spelling out what is required, including: the methodology to be used, the data to be published, the frequency of updates (perhaps every three years), and the stakeholder review process.

4. Meter Socket Adapters

JR 5-2026 specifically requires the new regulation to address meter socket adapters ("MSAs"). MSAs are UL-listed devices that plug into the existing utility meter socket to reduce the costs of solar, battery storage, and EV charger installations, save on materials, and avoid the need for expensive electrical panel upgrades. Products such as ConnectDER's Solar MSA, Enphase's IQ Meter Collar, and the Tesla Backup Switch are commercially available and widely deployed in multiple states.

Benefits of MSAs:

- Cost savings: MSAs that help avoid the need for an electric panel upgrade during the installation of solar, battery storage, or EV chargers can provide substantial savings to customers. MSAs cost approximately $500, compared to $2,500 or more for a traditional electrical panel upgrade. Similarly, MSAs that contain a Microgrid Interconnect Device (MID) to enable whole-home backup with solar and storage enable a far lower cost installation compared to the equipment and labor costs required to rewire a home's circuitry into a new critical loads subpanel to be served by a backup battery. This translates to significant savings for customers, particularly in Puerto Rico where affordability is a critical concern.

- Faster installation: One of the main benefits of Meter Socket Adapters is faster, simpler installations. MSA installations can take as little as 15–30 minutes to install, versus projects without MSAs which can require several additional hours or even days for panel upgrade work, rewiring tasks, and installation of additional components.

- Safety: MSAs are tested and certified to UL 414 and are designed to comply with ANSI Form 2S meter sockets, reducing installation variability and inspection failure rates compared to traditional panel modifications.

- Utilities and Ratepayers: Streamlined deployment of new customer-sited distributed energy resources enabled by MSAs result in the faster provisioning of incremental clean, cost-effective, and reliable capacity and power quality services to LUMA's grid.

MSAs are currently permitted by utilities in California, Arizona, Connecticut, Illinois, Maryland, New Jersey, Colorado, and many other states. However, existing PREPA rules (8915 and 8916) do not address MSAs at all, meaning the new rule will be written on a blank slate.

SESA's recommendation: The new rule must include prescriptive and enforceable language that clearly authorizes and establishes procedures for MSA installation. SESA's strong

recommendation is that solar installation companies that satisfy to-be-defined bonding requirements and that employ qualified electricians be permitted to remove the utility meter, install the MSA, and re-install the meter. By being bonded, the installer assumes liability for any damage that occurs during the process. This is critical because requiring a utility truck roll for every MSA installation would greatly reduce the cost and time benefits of MSAs.

The language must be written prescriptively—not merely permissively—to ensure that implementation details do not create procedural barriers that frustrate the legislative intent. Vague or permissive language risks allowing the utility to impose arbitrary product evaluation criteria, or installation or implementation requirements that make MSA adoption technically possible but practically prohibitive.

SESA recommends that the PREB host a dedicated procedural track or working group to develop a comprehensive MSA policy before the 180-day rulemaking deadline. Such MSA policy development should primarily focus on testing and evaluation by the grid operator of new MSA products and relevant installation processes and requirements. As a starting point, SESA recommends that PREB's MSA policy adheres, at a minimum, to the following principles and guidelines:

1. MSAs shall be customer-owned.

2. MSAs shall be installed in the customer's meter socket by a licensed and bonded third party solar installer.

3. MSAs must be listed by a nationally recognized testing laboratory (NRTL) to UL 414 or other applicable standard, must be suitable per the MSA's UL listing documentation for use in meter sockets of up to two hundred amperes, and must be approved by the grid operator for installation in its territory.

4. Customers shall notify the grid operator of their use of approved MSA products in their net metering notifications or applications.

5. Creation of a public-facing website by the grid operator that displays:

    a. Minimum MSA product and technical requirements and installation procedures
    b. MSA products approved for use in the grid operator's territory
    c. A newly created, dedicated intake email for new product evaluation requests from MSA manufacturers.

6. Other pertinent details and procedures to be discussed in the dedicated track/working group.

5. Daytime Minimum Load

JR 5-2026 specifically requires adoption of the daytime minimum load ("DML") concept. DML represents a modern replacement for the outdated "15% of peak load" threshold that has historically been used to trigger supplemental interconnection studies. Even LUMA has publicly stated, on multiple occasions, that there is no need for concern for systems on feeders under 30% penetration—confirming that the 15% threshold in Regulation 8915 is excessively conservative.

DML is not simply the measured distribution feeder minimum daytime load coincidental with solar production but requires further utility analysis. The PV System Impact Guide from the National Rural Electrical Cooperative Association (NRECA) correctly specifies the need to calculate peak and minimum gross load by adding the existing DER output to the recorded SCADA data. This calculation negates the impact of the existing DER on the load measured at the feeder and substation level so that total, raw load can be properly allocated[1].

If the utility simply relies on measured load data, the measured DML values have very limited utility forecast planning function. For example a distribution feeder with a measured SCADA load value of 500kW would make one assume that the distribution circuit is very close to back feeding distributed solar electricity from the distribution feeder into the substation, but this will not be the case and the engineer documenting DER notifications and applications could quickly believe the distribution circuits will have be at 500% DML, yet no power will leave the distribution feeder. If using NRECA's correct calculated DML approach a calculated gross DML of 100% would allow the utility to very accurately estimate when a distribution feeder has the potential to inject power back into the substation, so there should be an assessment by LUMA of their voltage regulators, substation transformer tap changes and other voltage management infrastructure to ensure they will properly regulate voltage in the event of reverse power flow into the substation. This is a far more accurate metric than measured peak or minimum load for assessing a circuit's ability to absorb customer generation.

Hawaii developed the original approach to properly calculate gross DML given the utilities concerns with Load Rejection Over Voltage as a distribution feeder approaches a state of reverse power flow. In conjunction with this proper DML assessment and testing of inverters response to load rejection, the utility in Hawaii developed an internal interconnection review process, that did not need to be approved by the Regulator and was pre-smart inverter

[1] https://www.cooperative.com/programs-services/bts/Documents/SUNDA/NRECA%20-%20SUNDA%20Impact%20Guide-v3%20final.pdf

adoption, allowing solar customer to readily interconnection of distribution feeders at 250% of calculated gross DML. In California, customer generators 30kVA or less have no DML/hosting capacity screen within the Rule 21 interconnection procedures.

At 100% of calculated gross DML, a circuit can readily accommodate distributed solar equal to the minimum amount of electricity being consumed on that circuit during daytime hours—meaning no power flows back beyond the substation. At 200% of calculated gross DML, a circuit can accommodate solar generation equal to twice the minimum calculated daytime consumption, which modern grid management tools and smart inverter settings can handle safely, particularly when paired with battery storage[2].

SESA's recommendation: The new rule should replace the 15% of peak load threshold with a calculated DML-based standard. Given Puerto Rico's high solar penetration, near-100% battery attachment rate, and the grid support services provided by smart inverters and batteries, SESA recommends this rule adopt a Minimum Daytime Load threshold based on stakeholder feedback, likely between 100% an 250%, and to consider exempting systems of a sufficiently small size of the need for any individual system evaluation. This would align Puerto Rico with the most modern interconnection practices and would be consistent with the statutory mandate to facilitate—not hinder—distributed generation.

[2] See. for example, California Public Utilities Commission, Data Portals and Integration Capacity Analysis, https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/infrastructure/distribution-planning/data-portals-and-integration-capacity-analysis
; Hawaiian Electric, Distribution DER Hosting Capacity Grid Needs, https://www.hawaiianelectric.com/documents/clean_energy_hawaii/integrated_grid_planning/distribution_der_hosting_capacity_grid_needs_03Aug2021.pdf
; and NREL, Smart Inverter Utility Experience in Hawaii, https://docs.nrel.gov/docs/fy19osti/74091.pdf

6. Compensation for Customers Suffering Curtailment Losses

JR 5-2026 requires the regulation to address compensation for economic losses to customers who experience export restrictions (curtailment) associated with imposed inverter configurations. This is a critically important consumer protection provision and must be a prerequisite for use of any function that risks substantial curtailment for customers such as Volt-Watt. Requiring settings that may result in major curtailment without this protection would shift an unacceptable amount of risk to customers and their solar installer given it would not be possible to know ahead of time what curtailment a specific system may be subject to. Even if only a small percentage of systems would face major curtailment, that still means hundreds or thousands of households, which is a material number.

If the Energy Bureau considers use of settings that could lead to curtailment, SESA recommends implementing clear guardrails to protect consumers.

SESA's recommended framework:

- **Minimize curtailment first:** The primary objective should be to minimize curtailment through proactive hosting capacity planning, grid upgrades, and appropriate inverter settings—rather than relying on compensation as a substitute for grid investment.

- **Define a materiality threshold:** Not all curtailment should trigger compensation. SESA recommends establishing a threshold above which curtailment is deemed "material" and triggers compensation. Hawaii's approach of using a monetary threshold over a defined period (e.g., losses exceeding a specified dollar amount over a three-month period)[5.1] provides a useful model[3].

  SESA suggests that a threshold in the range of $50 in lost energy value over a three-month period could be an appropriate starting point for consideration in Puerto Rico. Curtailment below this threshold would be considered de minimis and would not require individual compensation.

- **Clear compensation calculation:** When curtailment exceeds the materiality threshold, the compensation amount should be straightforward to calculate, based on the customer's actual energy losses valued at their applicable net metering rate. The process for reporting this information must be simple and LUMA must be held to

[3] *Order No. 41739 Approving the Hawaiian Electric Companies' Updated Volt-Watt Compensation Proposal,* Docket No. 2019-0323, issued May 29, 2025, which can be searched at https://hpuc.my.site.com/cdms/s/search

timelines that are appropriate for compensating the customer.

- **Mandate grid upgrade timelines:** Where curtailment is occurring at material levels, the utility should be required to undertake grid upgrades within a defined timeframe to resolve the underlying constraint. SESA acknowledges that the complexities of FEMA funding, supply chain challenges, and Puerto Rico's broader grid reconstruction may mean that upgrade timelines may not be as aggressive as in other jurisdictions. However, upgrade timelines should still be reasonable. While compensation for curtailment may accommodate longer upgrades timelines when necessary, the curtailment compensation process would still be a burden for the customer and therefore should not be relied on longer than is necessary.

7. Grid Operator Costs for Network Studies

JR 5-2026 requires the regulation to address how the grid operator's costs for network studies will be handled. SESA recommends a tiered approach that provides cost predictability while reflecting the different levels of utility effort required for different system sizes:

- **Systems up to 25 kW**: A single, known, fixed fee that all new net-metered systems pay at the time of interconnection notification. This fee should cover the utility's costs of processing the notification, any studies needed, and a contribution toward service transformer upgrades that may be necessary. For context, the current Regulation 8915 fee is $100 (the "net metering application fee"). Practices across the United States vary: California utilities charge $132–$145, Massachusetts charges $300 for systems over 3 kW, and Arizona utilities charge $75–$150. SESA recommends that increasing the fixed notification fee to approximately $250–$350 for all notifications may be appropriate for Puerto Rico, provided that this constitutes the customer's or soliciting company's total financial obligation as required by statute and that no additional study, upgrade, or supplemental charges may be imposed on systems up to 25 kW. This fee should be recharacterized as a "net metering notification fee" (rather than an "application fee") to reflect the automatic interconnection paradigm established by Law 17-2019. For systems up to 25 kW, the utility bears the general responsibility for maintaining the grid in serviceable condition, including proactive transformer sizing to accommodate the distributed generation growth that has been consistently adding 2,000–4,000 new solar customers per month for the past four years, and can be expected to continue at this rate for at least the next five years. Using applicable data from LUMA on average upgrade costs and frequency of upgrades can help inform what the appropriate fee level is for Puerto Rico.

- **Systems 25 kW to 1 MW:** A standardized per-kW fee that provides cost predictability for project developers. Currently, it is unknown in advance how much systems over 25 kW may need to pay for infrastructure upgrades, which prevents solar companies from accurately pricing interconnection costs in their initial proposals to clients. Moreover, LUMA has been routinely taking far longer than the statutory 90 days just to calculate what a project's cost contribution should be. Massachusetts uses a tiered approach of approximately $4.50/kW. SESA recommends establishing a simple per-kW fee schedule for systems between 25 kW and 1 MW, regardless of actual system-specific upgrade costs, so that interconnection costs are known upfront. This fee should be reviewed and adjusted periodically (e.g., every three years).

- **Systems 1 MW to 5 MW (or up to 20 MW):** Individual system-specific cost studies are appropriate for these larger systems, but with strict timelines for completion and clear methodology requirements.

C. Responses to the Energy Bureau's Unresolved Issues

The Energy Bureau's March 19 Order identified seven unresolved issues and invited comments on the TIR and Smart Inverter Settings. SESA addresses each below.

1. Scope of Technologies Included in the Regulation

Law 17-2019 refers broadly to "distributed generators," and Section 9 directs that interconnection procedures use FERC's Small Generator Interconnection Procedures (SGIP) as a model. The FERC SGIP is technology-neutral, covering solar, wind, combined heat and power (CHP), fuel cells, energy storage, and all other forms of distributed generation. Most modern U.S. state interconnection standards follow this technology-neutral approach; as of 2025, over 45 states have adopted interconnection rules covering diverse technologies.

SESA's recommendation: The new regulation should be technology-neutral, covering all distributed generation technologies—not only solar and batteries, but also wind, CHP, and any other qualifying distributed energy resources. While solar and battery storage will continue to represent the vast majority of interconnections in Puerto Rico, there is no legal basis for excluding other technologies, and CHP in particular serves important commercial and industrial customers.

Other than the statutory requirements that apply only to specific technologies (in particular, Automatic Interconnection for Net Metered solar systems under 25kW in size), the regulation should apply the same interconnection procedures to all technologies, while recognizing that

different technologies may have distinct technical requirements that should be addressed in the technical standards portion of the rule.

2. Interconnection Timeline and Enforcement

This is among the most critical issues for the new regulation. The law establishes two distinct interconnection paradigms that the rule must implement:

Systems up to 25 kW: Automatic Interconnection

Law 17-2019 establishes that photovoltaic systems up to 25 kW are interconnected automatically upon certification by a qualified professional. Net metering must be activated within 30 days of the utility receiving notice of the interconnection. However, there has never been a PREB-approved rule spelling out how this automatic interconnection is implemented in practice. The only existing implementation guidance consists of PREPA Comunicado Técnico 19-02 and Comunicado Técnico 20-01, which were drafted and published unilaterally by PREPA with no PREB involvement or approval.

SESA's position on Comunicados Técnicos: SESA posits that neither PREPA nor LUMA has the authority to publish binding technical memoranda governing interconnection without PREB involvement or approval.

The relevant content of Comunicados Técnicos 19-02 and 20-01 should be reviewed and, where appropriate, incorporated into the new PREB rule. PREB should declare those PREPA Comunicados Técnicos void as standalone regulatory instruments, and the new rule should clarify that any future technical memoranda or directives affecting interconnection procedures or requirements must have express PREB approval, be publicly posted on the PREB website in a clear, transparent, and accessible manner, and be developed through a process that includes meaningful stakeholder involvement.

Systems over 25 kW and up to 5 MW: 90-Day Maximum Review

Law 17-2019 provides that the utility's evaluation of interconnection applications for these systems shall not exceed 90 calendar days. If the utility fails to act within this period, the application is automatically approved by operation of law. However, there has never been a rule spelling out the details of how this 90-day requirement is enforced, or whether there are interim required steps and milestones leading up to the deadline. Meanwhile, LUMA's quarterly net metering compliance reports have repeatedly documented that for systems over 25 kW, LUMA routinely takes many months longer than 90 days to process interconnection applications.

SESA's recommendation: The new rule must establish a detailed process with interim milestones (e.g., completeness review within 10 business days, study scoping within 20 days, study completion within 60 days) and clear consequences for missed milestones, including automatic progression to the next stage if the utility fails to act. FERC Order No. 2023 (2023) provides a useful model: it eliminated the prior "reasonable efforts" loophole and imposed firm deadlines with financial penalties for transmission providers that miss timeline milestones.

California's experience—where utilities have achieved only 27% compliance with Rule 21 interconnection timelines over the past five years—demonstrates that timelines without meaningful enforcement are ineffective.

Systems between 5 MW and 20 MW

Currently, Regulation 8915 covers systems up to 1 MW and Regulation 8916 covers systems between 1 MW and 5 MW connected to transmission and sub-transmission. There is no regulation governing systems between 5 MW and 20 MW. Systems of 20 MW and above are generally considered utility-scale and are governed by separate large generator interconnection procedures. FERC's SGIP applies to facilities up to 20 MW.

SESA's recommendation: SESA recommends that the new interconnection rule extend coverage to include systems up to 20 MW, consistent with the FERC SGIP model that Law 17-2019 directs Puerto Rico to follow. This would close the current regulatory gap for systems between 5 MW and 20 MW.

3. Application Process and Review Tracks

For systems up to 25 kW:

The law already requires automatic interconnection for these systems. What has historically been called "fast track" is not an alternative or expedited pathway; it is the legally mandated standard process for all systems up to 25 kW. The new regulation should not frame automatic interconnection as an exception or a special track—it is the default and only process required by law for these systems. The current "net metering application fee" terminology should be changed to "net metering notification fee" to accurately reflect Law 17-2019's paradigm that these systems are automatically interconnected upon certification—no permission is being sought.

Regarding fees, the current Regulation 8915 establishes a $100 fee paid by all new systems. Historically, there was also a $300 Supplemental Study fee charged to customers on feeders exceeding the 15% penetration threshold. However, this $300 fee was conceived under the pre-Law 17-2019 paradigm where systems required utility approval before installation. Under

the current automatic interconnection paradigm, and given that the entire power grid has not been—and still is not—fully mapped (making it impossible to fully identify which systems are on feeders over the 15% threshold), PREPA and LUMA were unable to realistically collect this fee prior to interconnection. JR 5-2026 has now outlawed the Supplemental Study fee concept entirely.

SESA acknowledges that a reasonable fee is customarily paid by individual customers to support utility costs of processing interconnection notifications, conducting any necessary studies, and contributing to localized grid improvements such as service transformer upgrades. Best practices across the United States establish known, fixed fees for small systems: California utilities charge $132–$145, Massachusetts charges $300 for systems over 3 kW, and Arizona utilities charge $75–$150. The FERC SGIP pre-application fee is $300.

SESA's recommendation: SESA recommends that the new rule establish a fixed notification fee in the range of $250–$350 (an increase from the current $100) for all new net-metered systems up to 25 kW which interconnect after the effective date of the new Interconnection Rule. This would constitute the customer's total and complete financial obligation—no additional study, supplemental, or upgrade charges may be imposed.

We recommend that the amount of this fee could be subject to review on a predictable basis, outside the comprehensive rulemaking process – perhaps every 3 years – and could become lower or higher in the future.

One fixed fee for all customers interconnecting small systems in an approach adopted by many utilities across the nation and is recognized as best practice.

In considering the amount of this fee, we recommend giving credence to the substantial value that solar-plus-battery systems provide to the grid: they reduce daytime load strain, provide grid support services through smart inverter settings during the day, and—given Puerto Rico's near-100% battery attachment rate—add to the virtual power plant (VPP) capacity available to help prevent blackouts during evening peak hours. Furthermore, the current paradigm of reacting to individual interconnections must give way to proactive hosting capacity planning, where the utility plans for and budgets grid upgrades to accommodate the consistent 2,000–4,000 new solar customers being added monthly—a trend that has been sustained for four years and will continue for at least the next five.

For systems over 25 kW:

There must be standard, predictable pricing for interconnection fees. The current situation—where it is unknown in advance how much systems over 25 kW will need to pay for infrastructure upgrades—prevents solar companies from accurately pricing interconnection

costs into their initial proposals to clients. Compounding this problem, LUMA has been taking routinely far longer than the statutory 90 days to even calculate what a project's cost contribution should be.

SESA's recommendation: Establish a standardized per-kW fee schedule for systems between 25 kW and 1 MW so that interconnection costs are known upfront. Massachusetts provides a precedent with an approximately $4.50/kW tiered approach. The fee should be reviewed and adjusted periodically (e.g., every three years) to reflect actual costs.

4. Cost Allocation for Distribution System Upgrades

Cost allocation for distribution system upgrades is closely related to the fee structure discussed above. JR 5-2026 establishes that costs shall be determined in accordance with the principles of reasonableness, proportionality, and benefit received, and shall not be unfairly transferred to all customers of the electricity system.

SESA's recommended tiered approach:

- **Systems up to 25 kW:** The fixed notification fee (recommended at $250–$350) should be the customer's sole financial contribution. The utility bears general responsibility for keeping the distribution grid in serviceable condition, including proactive transformer sizing to accommodate DER growth. This fixed fee may contribute to service transformer upgrades where needed, but no individual cost allocation beyond this fee is appropriate for these systems.

- **Systems 25 kW to 1 MW:** The standardized per-kW fee should cover the customer's contribution to distribution system upgrades. This approach provides the predictability that project developers need while ensuring fair cost recovery for the utility.

- **Systems over 1 MW:** Individual system-specific cost studies are appropriate, but with strict timelines for completion, transparent methodology, and clear limits on the types of costs that may be allocated to the interconnecting customer versus the utility's general system improvement obligations.

5. Standard for Interconnection Studies

The most important principle for this issue is the requirement in JR 5-2026 for proactive hosting capacity planning and budgeting, coupled with the prohibition against charging individual supplemental study fees for systems up to 25 kW. Given that automatic interconnection is a legal right for all Puerto Ricans for systems up to 25 kW, the rule should not contemplate analyzing these systems one by one through a "permission granted or

permission denied" paradigm. Yes, the utility must be aware of every system on the grid. But automatic interconnection means the utility's role is to track, plan, and accommodate—not to approve or deny.

The ongoing emergencies caused by unreliable generation, fragile transmission and distribution infrastructure, vegetation management challenges, and climate-related events must also be acknowledged. Installing solar and batteries on one's own residence to provide stable power is not merely an economic choice—it has become a humanitarian necessity for many Puerto Rican families. The regulatory framework must reflect this reality.

There should be overall system planning to account for all existing and future solar, using cluster studies rather than individual system analyses. The old 15% of peak load threshold for supplemental studies is extremely outdated—even LUMA has publicly and repeatedly stated that there is no need for concern for systems on feeders under 30% penetration. But that 15% or 30% figure is measuring an outdated concept. JR 5-2026 requires a transition to the Daytime Minimum Load paradigm.

Daytime Minimum Load (DML) measures the lowest electrical load on a circuit during the hours when solar generation is at its peak. This is a far more relevant metric than peak load (which occurs in the evening) for assessing how much solar a circuit can safely accommodate. Hawaii has been a pioneer in DML-based screening, progressively raising thresholds from 50% to 100% of DML, with advanced implementations allowing 120–250% of DML. California's Rule 21 uses 100% of minimum daytime load as its screening threshold.

At 250% of DML, a circuit accommodates solar generation equal to 2.5 times the minimum daytime consumption—achievable with modern grid management, smart inverter settings, and battery storage. Given Puerto Rico's near-100% battery attachment rate and the grid support services batteries provide, the 250% threshold is both technically sound and consistent with the statutory mandate to facilitate distributed generation.

SESA's recommendation: Replace the 15% of peak load threshold with a DML-based standard as the screening threshold. Consider establishing screening thresholds of between 100% and 250% of DML, and consider the benefits and efficiencies of exempt the need for small systems to be evaluated on a individual basis altogether.

6. Interconnection Queue Management and Data Transparency

Systems up to 25 kW:

The quarterly net metering compliance reports that have been required since 2020 are doing a sufficient job of oversight for systems up to 25 kW. However, these reports have grown

excessively long and confusing as a result of dozens of orders issued from the bench during net metering compliance hearings over the years.

SESA recommends that the quarterly reports be drastically shortened and simplified to focus only on the most important monitoring metrics: (a) the extent of compliance with the 30-day net metering activation requirement for systems under 25kW and 90-day approval timeline for systems over 25kW and ; (b) quantification of solar and storage growth; and (c) identification of problems and facilitation of course corrections.

Systems over 25 kW:

The quarterly reports have repeatedly documented that for systems over 25 kW, LUMA routinely takes many months longer than the statutorily required 90 days. Additional oversight and enforcement mechanisms are clearly needed.

SESA's recommendation: For commercial interconnection (>25 kW), the rule should establish: (a) detailed milestone tracking with interim deadlines (e.g., completeness review, scoping, study, results, agreement); (b) automatic escalation to PREB when the utility misses a milestone; (c) an interconnection ombudsman function, either within PREB or through the expert facilitator, to resolve disputes without requiring formal litigation; and (d) periodic public reporting on commercial interconnection timelines and compliance. FERC Order No. 2023's approach of eliminating the "reasonable efforts" standard in favor of firm deadlines with financial consequences provides a strong model.

7. Technical Issues of System Performance

To the extent this issue refers to smart inverter settings and grid code requirements, SESA's input is as follows: The new interconnection rule must establish a clear, transparent process by which the utility, the regulator, or any major stakeholder may request amendments to current smart inverter settings.

The rule should spell out: (a) the procedure for submitting and evaluating proposed changes; (b) a defined timeline for PREB to consider such requests and issue a determination; (c) mandatory stakeholder consultation and a strong emphasis on consensus-building before any changes are approved; and (d) the requirement that no changes to smart inverter settings take effect without express PREB approval.

8. Contents of the TIR

SESA filed extensive comments and a detailed redline of LUMA's proposed TIR in December 2022 in this docket. Those comments identified numerous provisions of the proposed TIR that were overly conservative, outdated, or inconsistent with best practices, and proposed

specific revisions including: eliminating or substantially raising the 15% threshold; explicitly incorporating Law 17-2019's expedited pathway; modernizing definitions and aligning them across the rule and TIR; updating inverter settings to current IEEE 1547-2018 and UL 1741 standards; streamlining Fast Track screening; and converting all "average" timeline references to strict, enforceable deadlines. SESA incorporates its December 2022 comments by reference and stands by those recommendations, updated to reflect the requirements of JR 5-2026.

On the question of whether a TIR is needed at all:

There is no legal requirement for a separate TIR document. No existing law or regulation provides for, or contemplates, such a document. However, SESA recognizes that a practical argument can be made for separating detailed technical specifications from the procedural regulation, provided that appropriate safeguards are in place.

If a TIR is included, SESA's recommendations are:

- The entire initial TIR must be included in the text of this rule as an appendix or attachment, so that it undergoes the full formal rulemaking process with stakeholder input and PREB approval.

- The TIR must never be a document that the utility can change unilaterally without PREB oversight and approval. Under no circumstance should LUMA or any successor operator be permitted to modify the TIR without express PREB approval, and after chance for substantial stakeholder input.

- The rule must establish a clear procedure for future TIR amendments that: (a) is simpler than a full new rulemaking proceeding; (b) provides for adequate stakeholder input; (c) strongly encourages consensus among LUMA, solar and storage companies, the OIPC, and other major stakeholders before any changes are presented to PREB; and (d) establishes a clear timeline for PREB consideration and approval, denial, or approval with modifications. A flexible process defined within the regulation that allows for the subsequent modification of technical requirements without actually going through rulemaking, could announce and adopt the final decision of the Bureau via a Resolution and Order.

9. Smart Inverter Settings Amendments

The rule must define the process for amending any required smart inverter settings. SESA's recommendations:

- **PREB approval required**: Any changes to required smart inverter settings must receive express PREB approval before taking effect. Neither the utility nor any other party may unilaterally impose new smart inverter requirements.

- **Forward-looking only:** Mandatory smart inverter setting requirements may only be applied on a forward-looking basis, meaning they apply only to customers who interconnect after the changes are approved by PREB. This is a legal requirement—retroactive mandates on already-installed systems would constitute an impermissible taking of customer property rights and investment-backed expectations.

- **Implementation lead time:** The industry requires a minimum of four months (with six months being strongly preferred) to fully implement any new grid code changes resulting from smart inverter setting modifications. This time is needed for manufacturers to program and test firmware updates, update training materials, train installers, and deploy the changes to the field. The rule should establish a minimum implementation period so that any changes can be rolled out in an orderly manner for LUMA, manufacturers, installers, and customers.

- **Retroactive changes voluntary only**: Any smart inverter setting changes that PREB wishes to see adopted by already-installed systems must be on a voluntary or opt-in basis only. PREB may not mandate that existing systems be reconfigured. Customers should only be asked to voluntarily upgrade when doing so clearly makes sense for the customer's own interests. There are practical realities that may make updating smart inverter settings retroactively challenging or infeasible.

- **Consensus-driven process:** Smart inverter setting changes should be developed through a stakeholder process that strongly emphasizes and facilitates consensus among the utility, the solar and storage industry, consumer advocates, and the regulator. For example, smart inverter settings have been discussed in technical working groups in states such as New York and Massachusetts.

- **Volt-Watt should not be activated:** While settings such as Volt-VAR can provide critical grid support with minimal risk to system production, others such as Volt-Watt risk significant curtailment that would be largely unknown and unpredictable. Activating this system on <25 kW systems would pose a serious risk to the value proposition for households who install solar and storage and, as the interconnection rules are currently structured, they would be left with no recourse should they be severely impacted. As such, there should be no blanket activation of a Volt-Watt

setting, and any potential limited use of Volt-Watt must necessarily be paired with real consumer protection measures.

It is important to restate here the Energy Bureau's own established prerequisites for considering activation of Volt-Watt. The November 7th Resolution & Order in Docket NEPR-MI-2019-0009[4] which, on the topic of Volt-Watt activation, established that the Bureau would: "consider approving, through Resolution, the activation of this function [Volt-Watt] after considering: (i) recommendations from LUMA and Working Group regarding system performance, (ii) implementation of adequate reporting and tracking requirements for customer curtailment, and (iii) LUMA has developed an effective plan to manage distribution voltage, that relies on Volt-Watt functionality as a last resort mechanism to temporarily correct voltage issues."

Regarding those requirements, to date: 1. There has been no recommendation from the Working Group on this topic. 2. Reporting and tracking requirements for curtailment are not in place, nor has a process begun to start developing such reporting and tracking requirements, and 3. We are not aware of development or implementation of a plan on the part of LUMA to manage distribution voltage. Thus, none of the 3 requirements established by the Energy Bureau have been met; requirements which this Energy Bureau clearly established that must be met before considering any Volt-Watt activation.

Furthermore, as was presented by Sandia National Labs in the workshop on smart inverter topics held on March 31, 2026[5], the vast majority of voltage stabilization benefits happen with the Volt-VAR function rather than the Volt-Watt function. Sandia Labs presented a slide forecasting dramatically falling rates of customer curtailment as a greater percentage of customers have the Volt-VAR function enabled, with very little additional benefit from the Volt-Watt function also be activated, and with a zero curtailment paradigm once 50% or more of the DG systems have Volt-VAR activated, with no additional benefit from Volt-Watt at that time. That same slide shows that the vast majority of curtailment benefits occur at a percentage of 25% Volt-VAR deployment, a level which we have already achieved given that of the 200,000 net metered system, over 50,000 of them have been installed since January 1st 2025, the point at which the current smart inverter settings went into place. Thus over 50,000 of the existing 200,000 net metered systems already have Volt-VAR enabled, and are already providing dramatically positive voltage stabilization benefits.

---

[4] https://energia.pr.gov/wp-content/uploads/sites/7/2024/11/20241107-MI20190009-Resolution-and-Order.pdf

[5] NEPR-MI-2019-0009 Virtual Stakeholder Workshop, https://www.youtube.com/watch?v=GiRshWVYtKM

SESA's preference would be to avoid the use of the Volt-Watt function and avoid other smart inverter settings which trigger unreasonably high levels of curtailment. Such an approach would be simpler to implement and avoid the inevitable administrative challenges of administering a curtailment compensation process. The Energy Bureau must first make sure that the 3 requirements it established by Resolution have been met before considering any Volt-Watt activation, and should also see if use of settings, such as Volt-VAR, which is enabled on an ever-increasing number of solar installations, is able to resolve solar-related voltage issues before taking action on Volt-Watt.

As noted in the National Labs presentation, there were sites where voltage was abnormally high both day and night which indicates feeder or local-level issues that necessitate work from LUMA to address. If settings such as Volt-Watt were activated on these sites, those customers would face incredibly high levels of solar curtailment for issues that are unrelated to solar. This would be an inequitable outcome. Also, the voltage and frequency regulation that is expected of the Puerto Rico grid and its operator when assessing what is abnormal for customer protection, must be clearly defined. For voltage, this commonly either ANSI C84.1 Range A or Range B.

- **Power Control Systems (PCS):** PCS is technology that limits the amount of electricity a customer's system exports to the grid, and in other U.S. jurisdictions is sometimes offered to interconnecting customers as an alternative to paying for grid upgrades or downsizing their system. Because PCS was not a mature technology when Puerto Rico's current interconnection rule was developed, SESA flags this as a topic the Bureau may need to address in some form through this rulemaking.

  We also note that activating PCS necessarily means curtailing or limiting a customer's output, which raises the question of whether and how customers would be compensated for that curtailment — an issue that would need to be worked through before any PCS framework could be adopted. Naturally, how PCS may potentially be used will also be dependent on a variety of other factors such as how interconnection upgrades and associated cost allocation is handled or use of smart inverter settings.

  SESA does not have a specific recommendation for use of PCS at this time but notes that the technology provides functionality that should be considered in this proceeding.

D. Input on Format of Document for New Interconnection Rule

The Energy Bureau must decide what document(s) to use as the base or framework for the new interconnection regulation. There are two primary candidates:

Option 1: PREPA Rules 8915 and 8916 (Recommended Starting Point)

These are the current "law of the land" and represent the framework that all stakeholders—utilities, regulators, installers, and customers—are familiar with. However, they have significant structural shortcomings: extensive repetitive content, and an intermingling of highly specific technical requirements with procedural requirements throughout both documents.

SESA's recommendation: Use Rules 8915 and 8916 as the starting framework, but combine them into a single comprehensive rule and restructure to clearly separate procedural requirements from technical requirements. The procedural portion of the rule would govern application processes, timelines, fees, enforcement, and stakeholder rights. The technical portion (whether maintained as a section of the rule or as a separate appendix/TIR with appropriate safeguards as discussed above) would address engineering standards, equipment specifications, inverter settings, and testing requirements.

Option 2: PREB-Published Draft Rule (Summer 2021)

This draft, developed by the Interstate Renewable Energy Council (IREC) and published by PREB, disregarded many aspects of Rules 8915 and 8916. The document is lengthy, was developed with no local stakeholder input prior to publication, and attempted to micromanage implementation details in ways that may not be practical for Puerto Rico's specific context.

SESA's recommendation: This document should not be used as the base framework. While it may contain useful concepts and provisions that can be selectively incorporated, starting from this document could be viewed as essentially rebuilding from scratch, which may not be the most efficient use of the limited time available under JR 5-2026's deadlines.

Open Question: How to best handle LUMA's Proposed TIR (2022)

The most recent version of LUMA's proposed TIR was presented in November 2022—now over three years ago—making it rather dated. Moreover, a complete version of what LUMA intended

to present was never finalized; only a redline of previous versions exists, with some components still missing.

It's important to note that JR 5-2026 mandates timelines for implementation of a draft and final rule, and that LUMA has proposed that a TIR be considered as something somewhat separate from the rule itself.

Even if this is the case, it's important that any content of a TIR which is necessary for a rule to be considered complete and enforceable, would need to be included in the rule itself.

The prevailing question when analyzing how to treat the TIR as part of this rulemaking, is to what degree current Puerto Rico law and rules provide for the concept of a TIR.

SESA's recommendation: As discussed above, SESA has significant concerns about the legality of a standalone TIR document. If a TIR is ultimately included as part of the new rule, the content of what concepts belong in a TIR as opposed to the more fixed rule itself should be developed collaboratively through the workshop process, rather than assuming that the most recent version of LUMA's proposed TIR is necessarily the best starting point.