

**GOVERNMENT OF PUERTO RICO
PUERTO RICO PUBLIC SERVICE REGULATORY BOARD
PUERTO RICO ENERGY BUREAU**

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Interconnection Regulations**

Docket No. NEPR-MI-2019-0009

**COMMENTS OF THE INTERSTATE RENEWABLE ENERGY COUNCIL, INC. ON
DISTRIBUTED GENERATION AND MICROGRID INTERCONNECTION
REGULATION**

1. INTRODUCTION

Pursuant to the Puerto Rico Energy Bureau's ("Energy Bureau") September 16, 2026, Request for Comment, the Interstate Renewable Energy Council, Inc. ("IREC") respectfully submits these comments on the draft proposed revisions to the simplified interconnection process, the Fast Track process, smart inverters, pro-active planning, and the economic dispatch of DERs.

2. BACKGROUND

IREC is a 501(c)(3) non-partisan, non-profit organization working nationally to build the foundation for rapid adoption of clean energy and energy efficiency to benefit people, the economy, and our planet. In service of our mission, IREC advances scalable solutions to integrate clean energy resources, including solar, energy storage, electric vehicles, and smart inverters, onto the grid safely, reliably, and affordably. IREC supports the creation of robust, competitive clean energy markets, though IREC does not have a financial stake in those markets. IREC's team includes policy experts, lawyers, and electrical engineers who are well versed in the procedures and technical standards for interconnecting clean energy to the electric power system. Drawing on that knowledge, IREC works across numerous diverse states to improve the rules, regulatory policies, and technical standards that enable the streamlined, efficient, and cost-effective interconnection of clean energy resources. IREC has extensive experience with state

interconnection procedures and has helped to refine and improve interconnection procedures across the United States for over 20 years. IREC closely monitors and tracks the development of best practices in interconnection policy, with a focus on both the procedural and technical aspects of interconnection and regularly updates the only interconnection guide in the U.S., IREC's Model Interconnection Procedures.

3. IREC COMMENTS

IREC appreciates the opportunity to respond to the September 16, 2026, Request for Comments. Below, we include the following recommendations on the Simplified process, the Fast Track process, smart inverters, pro-active planning, and the economic dispatch of DERs.

- a. The Energy Bureau should retain provisions that base eligibility for the Simplified review tier on export capacity, rather than nameplate capacity.
- b. The Energy Bureau should narrow the scope of the post-interconnection review for Simplified systems to only secondary issues.
- c. The Energy Bureau should consider motivating export limitation for Simplified systems.
- d. The Energy Bureau should modify the shared secondary screen to use 100% of the transformer nameplate rating.
- e. The Energy Bureau should enable customers to revise their application after screen and study results.
- f. The Energy Bureau should ensure smart inverter functions in the TIR contribute to feeder voltage stabilization.
- g. The Energy Bureau should define proactive planning and continue developing its implementation.
- h. The Energy Bureau should address the economic dispatch of DER systems in another proceeding.

a. The Energy Bureau should retain provisions that base eligibility for the Simplified review tier on export capacity, rather than nameplate capacity.

In Article 3.A.(1), of the September 16 revised preliminary draft regulations, the Energy Bureau proposes to eliminate language that would base fast track eligibility on Export Capacity rather than nameplate. IREC strongly opposes this revision and urges the Energy Bureau to retain the original language. The original language of allowing projects with a nameplate capacity that does not exceed 50 kW and an export capacity that does not exceed 25 kW to use

the Simplified review tier is critical to enabling solar and energy storage projects or any storage project that is unlikely to export at full capacity. Basing the Simplified review tier on export capacity ensures that projects will be evaluated on actual performance and grid impacts rather than worse-case scenario assumptions. This approach is reasonable because the majority of potential impacts from projects are a result of exported power. If a project's export is limited, the only increased distribution system impacts that could occur from the project's higher nameplate rating are those related to fault current and the maximum export-related impacts can be substantially lower than those implied by the DER's gross nameplate capacity. However, the fault current contribution from projects as small as 50 kW is likely to be insignificant. All inverter-based projects contribute very little fault current to the system relative to rotating machines, and projects below 50 kW are therefore very unlikely to meaningfully impact the amount of fault current on the distribution system or the coordination of protective devices. However, the utility should retain the ability to evaluate protection impacts where system-specific conditions warrant.

Basing eligibility on Export Capacity is prudent to allow DER systems with large amounts of AC-coupled storage to interconnect under the Simplified track. AC-coupled battery energy storage systems are often stacked in parallel to achieve a desired kWh capacity, regardless of whether the additional power (kW) is needed. Therefore, a modestly sized PV system coupled with several storage units can easily exceed a 25 kW nameplate rating. Certified power control systems using a power export limit can ensure that only a maximum of 25 kW (or less) ever flows to the grid. The nameplate rating cap of 50 kW ensures that very large systems do not try to interconnect with reduced evaluation, while still allowing for a reasonable amount of AC-coupled storage, though this number could be increased in consultation with LUMA and developers.

b. The Energy Bureau should narrow the scope of the post-interconnection review for Simplified systems to only secondary issues.

In Article 3.C.(4). of the revised preliminary draft regulations, the Energy Bureau proposes that LUMA can identify “specific safety or reliability concerns” during the post-interconnection review and notify the customer of necessary corrective actions. IREC is

concerned the proposed language grants LUMA too broad discretion to assign feeder or substation level upgrades to Simplified systems.

For instance, this could result in million-dollar level upgrades, such as conductor replacement, being assigned to Simplified customers. Due to the unique law that allows Simplified customers to connect before evaluation, having any major cost assigned to a single customer introduces an untenable level of risk for any customer desiring to interconnect. The upgrade-funding fee defined in Article 3.B is unlikely to create a large enough pool of funding for all the feeder-level upgrades needed across the distribution system, and for which a Simplified system could be perceived to contribute to. This funding mechanism needs further exploration in the record to see what upgrades could likely be covered. However, if only secondary-level upgrades (distribution transformers and service conductors) can be feasibly covered, then the post-interconnection review should only address the Simplified system's effect on those upgrade needs¹. In this paradigm, customers can continue to interconnect before utility review, but may need export restriction until a distribution transformer or secondary upgrade is completed, which should be much faster than larger scale feeder upgrades. The larger feeder or substation upgrades could still be identified but would be handled through the proactive planning or regular planning processes. IREC recommends the provision be modified, and incorporate the following revisions in red text, to reflect the focus on secondary issues:

*"3.C.(4). To ensure the ~~reliability~~ **reliability** and safety of the EPS, the EPS Operator may conduct a post-interconnection review within fifteen (15) Business Days after receipt of the Simplified Interconnection Notification and Agreement to verify compliance with applicable safety and reliability requirements. **The EPS Operator shall evaluate if the transformer or secondary conductor rating is exceeded by the aggregate Export Capacity, including the proposed Distributed Generation System or Microgrid. If either of the ratings are exceeded, and the EPS Operator identifies a specific safety or reliability concern on the secondary or distribution transformer, it shall notify the Interconnection Customer in writing of the basis for that determination and any corrective action required...**"*

It is important to note that distribution transformers may be overloaded for periods of time before significant issues occur, which may be already commonplace in Puerto Rico. While it is challenging to incorporate language that guides the specific conditions under which the utility should allow overloading, the above language notes that assessing at the rating of the

¹ For example, if 20,000 Simplified systems interconnect within a year, with a \$300 fee, this creates an upgrade pool of \$6 million. If the average cost of a transformer replacement is \$10,000, then 600 transformers can be covered by the pool, reflecting just 3% of Simplified applications.

transformer is the minimum, and LUMA may allow operation at a higher level at its discretion if it does not identify a safety or reliability concern. This allows LUMA to conduct a more sophisticated analysis of the secondary to identify safety or reliability concerns as appropriate. In the future, AMI 2.0 meters may allow for DERs to be managed such that export levels can scale in real time with the load on the transformer, as measured by the AMI meters. In that case, a higher aggregate Export Capacity would be acceptable since the DER would be controlled as needed.

It is also important that this evaluation be based on Export Capacity. The effects of DERs could be overestimated by comparing nameplate ratings to the secondary or transformer ratings. Especially with AC-coupled energy storage present, nameplate rating is not reflective of the actual effects on the secondaries. However, even with these proposed edits, the main motivation for a customer to implement export limiting is to avoid secondary upgrades. This may or may not be enough to ensure multiple customers on a transformer have access to the transformer capacity for their DER systems. This is discussed in more detail in the following section.

As in the case of the Fast Track shared secondary screen (see section d below), we recommend the full capacity of the secondary conductors and transformers be used in this evaluation and allow inverter voltage regulation functions to address voltage issues.

c. The Energy Bureau should consider motivating export limitation for Simplified systems.

In some jurisdictions, energy storage is restricted from exporting through the NEM rules, and this restriction, managed by a certified power control system, will reduce the Export Capacity. We do not recommend a technical restriction be made in relation to the NEM rules in Puerto Rico. In the future, Puerto Rico will want the ability for energy storage systems to export to support the bulk grid en masse, so a technical restriction should not hamstring this capability. However, there may be a need to motivate Simplified customers to utilize export limiting equipment, such that it is clear there will be limited effects of DER on secondaries, rather than assuming the full nameplate rating may present itself. IREC does not make a recommendation on how or if this should be done at this time, as more discussion would be needed to implement any

restriction. If an export restriction is implemented, this could take the form of either a static limit or hourly schedule if the equipment is capable.

As mentioned above, DER output on shared secondaries could be a dynamic function of actual load/output measured by the AMI system and managed by an application in the meter itself.² This may be ideal, though it is a solution that is likely to be years away. IREC does suggest that the Bureau investigate this concept in a successor proceeding. In the meantime, any technical limits on export, using a power control system limitation, will potentially hamper future export capability unless this can easily be modified in the future (such as remotely by manufacturers).

It may, however, be fair to create an approach that ensures shared transformer capacity is not dominated by a single customer, or that the last customer to apply for interconnection isn't left with a small sliver of capacity or a required upgrade. This could mean limiting each Simplified customer's Export Capacity allowance to some percentage of a typical distribution transformer's rating. For example, if it is common practice to use a 25 kVA transformer for five residential customers, then a 5 kW Export Capacity limit per customer would help ensure the transformer is not overloaded. This could also ensure fair access to any future incentivized export program, where storage helps manage demand on the grid by exporting at certain times of the day. This will, however, beg the question of how to manage this limit if transformers are upgraded in the future and upsizing is needed for additional load, such as EV chargers.

South Australia implemented such a 5 kW export limit earlier on. As rooftop solar began to constitute a very large portion of the grid's generation, as it may in Puerto Rico one day soon, they found a need to reduce exports at times to maintain safety and reliability. To continue with a static limit based on worst-case loading would have resulted in a reduced export limit of 1.5 kW per customer. Instead, they have transitioned to a dynamic export limit that is managed by a distributed energy resource management system (DERMS). This system allows export up to 10 kW when capacity is available, which is the case most of the time. It will curtail systems down to 1.5 kW as needed, or 0 kW in emergency conditions. The 1.5kW static export limit remains for

² For example, PG&E's ChargeBoost program modulates EV charger output based on transformer load. <https://www.pge.com/en/clean-energy/electric-vehicles/getting-started-with-electric-vehicles/chargeboost.html#accordion-229df50551-item-8b881bfab6>

customers that opt out of dynamic limits. It is important to note that Australia does not have distribution transformers arranged similarly to distribution in the US, so the specific export limit number is not applicable. However, developers or manufacturers can likely provide data on typical export levels on residences in Puerto Rico to help understand what the tradeoffs of any particular limit would be. IREC encourages discussion as to whether this type of limit is feasible for all parties, and if so, what the limit should be.

If an export limitation cannot realistically be included, then there will need to be other methods to ensure the utility is not overestimating the effects of DER on the secondaries. That could potentially include guidance on how energy storage capacity is handled differently from PV capacity in the evaluation.

d. The Energy Bureau should modify the shared secondary screen to use 100% of the transformer nameplate rating.

The 65% threshold for this screen in IREC's Model Interconnection Procedures is based on voltage rise concerns on secondaries, and has been used in interconnection rules for over 15 years.³ This screen, however, has not been updated for the use of voltage regulation functions of smart inverters. For jurisdictions where the volt-var (and perhaps volt-watt) function is implemented on all inverters, we expect the overvoltage to be mitigated. In that case, the secondary constraint that remains is the thermal capacity. Therefore, we recommend revising this screen and basing the threshold on 100% of the transformer rating as well as checking the secondary conductor rating:

*"4.02(B)(6) If the proposed interconnection is on single-phase shared secondary, the aggregate Export Capacity on the shared secondary, including the proposed Distributed Generation System or Microgrid, shall not exceed ~~sixty five percent (65%)~~ of the transformer nameplate **or secondary conductor** rating."*

³ Robert J. Broderick and Abraham Ellis, *Evaluation of Alternatives to the FERC SGIP Screens for PV Interconnection Studies*, Sandia National Laboratories (2011)

- e. **The Energy Bureau should enable customers to revise their application after screen and study results.**

IREC recommends that the Energy Bureau establish a pathway for allowing minor project modifications for projects that fail the screening or study process. Inserting this language helps proposed projects avoid or minimize grid impacts, bypass further evaluation, and the need for queue withdrawal. It will also help reduce disputes and accelerate timelines. While Article 4.04.(E). of the revised preliminary draft regulations does mention that customers can “consider minor modifications” before proceeding to the study process after a supplemental review failure, the current language is too vague and does not establish clear process steps, timelines, or responsibilities. The language proposed below, with revisions in red, would create transparent, efficient, and accountable minor project modification processes within the supplemental review and system impact study sections of the regulations. The Energy Bureau should also consider adding similar provisions in the Fast Track Initial Review (Section 4.02).

SECTION 4.04. Supplemental Review

*“(E) If the proposed interconnection fails **any of the supplemental review screens**, the EPS Operator shall specify which screens the interconnection application failed, including the technical reason for failure, and the data and the analysis supporting the supplemental review. The EPS Operator shall provide information and detail about the specific system threshold or limitation causing the interconnection application to fail the screen. If the Interconnection Customer chooses to amend the interconnection application to address the specific failed screens, the Interconnection Customer must submit an updated interconnection application demonstrating the redesign within 10 business days after receiving the screen results. The redesign shall only include changes to address the screen failures or identified upgrades (which could include, for example, the addition of DC-coupled or AC-coupled energy storage). Increases in export capacity or changes in point of interconnection are not permitted and shall require the interconnection application to be withdrawn and resubmitted. The EPS Operator will evaluate whether the redesign addresses the screen failure and notify the Interconnection Customer of the results of this evaluation within 10 business days. This redesign option to mitigate impacts shall only be available one time during the supplemental review process. If the Interconnection Customer does not amend or withdraw its interconnection application within 10 business days of receiving results, it shall continue to be evaluated under the study process consistent with Article 5. ~~the screens, and the EPS Operator does not or cannot determine that it may nevertheless be interconnected consistent with safety, reliability, and power quality standards unless the Interconnection Customer will consider minor modifications or further study, the EPS Operator shall provide the customer the option of commencing the Study Process in Article 5. If the Interconnection Customer wishes to proceed it shall notify the EPS Operator within fifteen (15) Business Days to retain its queue position.~~”*

SECTION 5.04. System Impact Study

“(I) A one-time modification of the interconnection application is allowed as a result of information from the system impact study.

(a) If the Interconnection Customer chooses to amend the interconnection application to address the specific system impacts, the Interconnection Customer must submit an updated interconnection application demonstrating the redesign within 15 business days after receiving the system impact study results from the utility. The redesign shall only include changes designed to address the specific system impacts or identified upgrades (which could include, for example, the addition of DC-coupled or AC-coupled energy storage). This redesign option to mitigate impacts shall only be available one time during the study process. Increases in export capacity or changes in point of interconnection are not permitted and shall require the interconnection application to be withdrawn and resubmitted;

(b) The EPS Operator shall notify the Interconnecting Customer within ten business days of receipt of the modified interconnection application if any additional information is needed. If additional information is needed or document corrections are required, the Interconnection Customer shall provide the required information or corrections within 10 business days from receipt of the utility notice;

(c) The actual costs to the utility for any necessary restudies as a result of a modification described above shall be paid by the Interconnection Customer. Such restudies should be limited to the impacts of the modification and shall be billed to the Interconnection Customer at cost and not for work previously completed. The EPS Operator shall use reasonable efforts to limit the scope of such restudies to what is necessary. The revised impact study shall be completed within 15 business days.”

f. The Energy Bureau should ensure smart inverter functions in the TIR contribute to feeder voltage stabilization.

The Technical Interconnection Requirements (TIR) required by the draft regulation should contain, among other inverter settings, activated voltage regulation settings which mitigate voltages on the secondaries, and contribute to voltage mitigation on the primary feeder. While activating these settings will not correct for previously connected legacy systems or pre-existing feeder voltage regulation issues, moving forward they will ensure that inverters are contributing to mitigate the voltage effects of DER. These voltage regulation strategies, such as volt-var, will work in parallel with other measures like proactive planning and economic incentives to maintain voltages within the normal range. IREC encourages the Bureau to convene discussion of these voltage regulation settings to optimize their hosting capacity benefit as part of the adoption of the TIR in 2027.

g. The Energy Bureau should define proactive planning and continue developing its implementation.

IREC strongly encourages the Energy Bureau to define proactive planning concepts as part of this docket, and order LUMA to file details on how they will carry out those concepts in this docket, extended into 2027, or a successor docket. IREC bases its understanding of a useful proactive planning approach on Hawaiian Electric's practices, which have helped expand hosting capacity as DER penetrations have continued to rise across the islands. This approach works generally along these lines: 1) the utility monitors hosting capacity utilization by comparing distributed hosting capacity estimates (via hosting capacity analysis software such as EPRI's DRIVE) to forecasted DER adoption/interconnection application levels, 2) feeders and substations that are reaching capacity receive planned upgrades based on forecasts, and 3) systems that connect when hosting capacity has already been reached may have to wait for operation or operate in a non-export mode until a planned upgrade is completed.

Proactive planning in Puerto Rico may look *reactive* at the start due to the previous influx of interconnected DER and lack of distribution system upgrades. In this case, LUMA should identify feeders at the highest penetration levels relative to hosting capacity, and target those feeders for upgrades, while balancing equitable distribution of benefits to underserved communities. This will also be an opportunity for LUMA to implement grid modernization and operational changes that could further benefit DER hosting capacity as well as prepare these circuits for electrification. For instance, voltage regulation practices such as conservation voltage reduction (which can increase voltage headroom for more DER backfeed) or bi-directional line drop compensation controls could be implemented along with capacity upgrades. As the Puerto Rican grid is rebuilt, it will be important to consider how to best integrate DER—including solar, batteries, V1G and V2G systems—with grid controls and operations. This plan will require significant work beyond the timeline of the current proceeding to implement.

In other venues such as in Minnesota, IREC is developing methods to determine the cost allocation of proactive upgrades based on the shares attributable to DER benefits and load benefits. This methodology is likely more suited to allocating costs to large DER rather than the residential level which predominates in Puerto Rico. This type of methodology may still be reviewed and modified as needed, but different structures may be more appropriate for Puerto Rico, which may wish to ensure the ability of DER, and especially distributed energy storage, to support bulk grid operations and contribute to resilience.

The Energy Bureau will want to ensure the proactive planning process is effective at helping set up the Puerto Rican grid for a sustainable and reliable energy future. While the Hawaiian example is the best example IREC is aware of for these purposes, the process will likely need to be tailored for Puerto Rico's needs. New forecasting methods and community engagement may be necessary to direct investments to the appropriate locations. This process will include balancing overdue upgrades, grid equity, grid modernization, resilience and cost allocation approaches. Thus, IREC recommends that the Energy Bureau set up the general methodology of proactive planning within this docket, and extend decisions on the numerous related issues into 2027.

h. The Energy Bureau should address the economic dispatch of DER systems in another proceeding.

Much of the potential problems with unconstrained growth of small-scale DER in Puerto Rico is related to the impact on feeder voltage. Due to the mismatch between PV output and load consumption locally, voltages can rise in the middle of the day as many small systems export. At the same time, most PV systems installed on the island also have paired energy storage which is reserved for much-needed off-grid resiliency. At the moment, there is little incentive for these energy storage systems to contribute to voltage mitigation by shifting use of solar energy or exports to hours when the load requirements are higher. In addition to their inclusion in a virtual power plant, these storage systems could be of great benefit for the grid, both as a means to reduce midday peaks in voltage as well as a source of clean energy to serve load, reducing strain on other generating assets.

While not directly related to this docket, IREC recommends the Energy Bureau consider ratemaking and incentive programs to ensure the robust deployment and management of storage systems throughout the distribution system. The Energy Bureau can take a layered approach to ensure the interconnection of DER systems benefits the grid. A non-technical, economic solution can be deployed while grid upgrades are underway. For instance, storage incentives (or export disincentives) can help ensure a large portion of PV systems charge storage midday, rather than exporting when load is low. Those incentives can shift export to the peak hours, which should

generally help to mitigate high voltage and reduce stress on other generating assets and the transmission system. Time-of-use rates or export tariffs (as Australia has implemented) could be designed as economic signals used to shift generation to useful hours, amongst other potential strategies.

4. CONCLUSION

IREC appreciates the opportunity to comment on the September 16 Request for Comments and for the Energy Bureau's attention to these issues. We believe the Energy Bureau has the opportunity to help reshape the grid in Puerto Rico through a layered approach that addresses technical, process and cost allocation approaches in the Interconnection Regulation, proactive planning, smart inverter functionality, and economic fixes. When taken together, this approach can create the opportunity for customers to become part of the solution that will increase the resiliency and reliability of the grid. We look forward to continuing to work with stakeholders in Puerto Rico to help align the state's interconnection rules and related processes with national best practices, and to forge a new, integrated approach for incorporating customer-owned energy resources on the grid.

Sincerely,

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