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August 23, 2023

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# Acadia Center Comments on RI Energy 2024-2026 SRP Three Year Plan

Dear Ms. Gill:

Acadia Center believes there is significant potential for Rhode Island Energy and other parties to integrate electric and gas utility planning to focus more holistically on customer energy needs, rather than considering each fuel's distribution system in its own silo. As we seek to decarbonize our energy system, it is increasingly necessary to analyze both the gas and electric distribution networks together while identifying potential solutions to meet grid needs. Acadia Center strongly supports the use of non-wires alternatives (NWA) and non-pipes alternatives (NPA) as tools to lower customer and utility costs, lower emissions, and to help facilitate the deployment of clean energy resources. We greatly appreciate Rhode Island Energy's efforts to develop a robust System Reliability Procurement (SRP) Three-Year Plan for 2024-2026.

## Benefits of Non-Wires and Non-Pipes Alternatives

Non-wires alternatives (NWA) and non-pipes alternatives (NPA) include technologies and energy services that can delay or defer traditional transmission and distribution infrastructure investments. NWA and NPA can include energy efficiency, demand flexibility, managed charging, battery storage, dynamic and time-varying pricing, solar PV, microgrids, and other distributed energy resources (DERs). NWA and NPA can consist of individual technologies or a portfolio of resources that meet a grid need in a more cost-effective way than traditional wires and pipes solutions.

NWA and NPA have the potential to provide significant benefits to ratepayers and grid operators in Rhode Island. By avoiding the need to pay for large infrastructure investments that may become unnecessary in the future, NWA and NPA can save ratepayers significant amounts of money. As Rhode Island seeks to meet its climate and energy targets, it is critical to avoid wasting ratepayer funds on infrastructure that may become financially stranded, in which case the infrastructure is no longer needed but still needs to be paid for.

Rhode Island's electricity grid will likely change considerably in the coming decades as the state reconfigures the infrastructure required to bring unprecedented amounts of utility-scale and distributed energy resources online to meet Rhode Island's climate and energy goals. By deploying NWA and NPA rather than more expensive traditional infrastructure that locks in solutions for many years, grid operators in Rhode Island will benefit from much greater flexibility. NWA and NPA can allow grid operators to quickly adapt and modify resources as grid conditions change over time.

To successfully reap the benefits that NWA and NPA offer, screening and solicitation for alternative solutions must become a business-as-usual practice within utility planning, rather than consisting of one-off projects that are separate to normal utility operations. We applaud the integration of the system reliability procurement process into the overall electric and gas system planning and offer the following recommendations in service of evaluating all possible NWA and NPA solutions on a level playing field.

## System Needs Data Should Be Comprehensive, Transparent, and Made Available in a Timely Manner

Acadia Center appreciates the information provided by RI Energy on the SRP process overall, as well as the summary of categories included in electric and gas system needs assessments.[1] Acadia Center respectfully requests more detail from RI Energy on the data that will be included in system needs assessments and recommends looking to Connecticut's recently approved Non-Wires Solutions program as a helpful example of comprehensive system needs data.

Connecticut's Public Utilities Regulatory Authority (PURA) requires annual grid needs data filings from its electric distribution companies (EDCs) as part of its Non-Wires Solutions program. The annual filings must include detailed distribution system, financial, and distributed energy resource deployment information. (See Attachment A for a copy of the "Requirements for Annual EDC Data Filing" as part of Connecticut's Non-Wires Solutions Process Design Document.[2]) While that program is specifically focused on non-wires solutions, a similarly detailed list of requirements for gas system needs would also be appropriate. By providing detailed grid needs data in a timely manner, which may be mandated by the regulatory authority or voluntarily provided by the utility, third-party providers will be better positioned to provide targeted solutions that meet both location- and time-dependent distribution system needs.

Grid needs data provided by RI Energy should incorporate DER forecasts that are spatially granular, e.g. at both the substation and feeder levels. In addition, grid needs analysis should endeavor to disaggregate load forecasts to assess individual end uses and better understand the impacts of DERs on load profiles, including the role that measures like energy efficiency and demand flexibility can play in improving hosting capacity.

Acadia Center would also appreciate more detail on RI Energy's timeline for providing grid needs assessment data to the Public Utilities Commission and to potential third-party providers. How long would third-party providers have to respond to any Request for Proposal? Acadia Center urges RI Energy to structure RFPs and competitive solicitations in a sufficiently accessible way that enables third-party providers to put forward robust solutions. RFPs should be actionable and focused on solving a particular problem, not seeking a particular technology. They must allow for sufficient time for third-party providers to assess the opportunity and develop a coherent proposal in response to grid needs data. Third-party providers should have transparent access to data about performance needs, capacity constraints and hosting capacity, granular load profiles, estimated costs for traditional solutions, customer demographics, among other grid needs categories.

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[1] RI Energy. 2024-2026 System Reliability Procurement Three-Year Plan, at 11 and 12.

[2] CT PURA. Docket No. 17-12-03 RE07. Connecticut Non-Wires Solution Process Design Document, https://www.dpuc.state.ct.us/2nddockcurr.nsf/8e6fc37a54110e3e852576190052b64d/59e888f10a5de7d2852588f5005b106c/$FILE/171203RE07-110922%20Appendix%20A%20-%20NWS%20Process%20Design%20Document.pdf

Section 7 outlining RI Energy's Annual Reporting requirements to the Rhode Island Public Utilities Commission (PUC) is an essential process for ensuring that RI Energy has taken appropriate steps to fully compare NWA, NPA, and traditional investments. As part of the results of screening for electric and gas system reliability procurement opportunities, RI Energy's annual SRP reports should provide specific detail on why a particular solution was chosen or not chosen.

## Engage an Independent Process Monitor and Evaluator

While Rhode Island Energy has unique insight into the electric and gas distribution systems, there may be potential risks to the success of the SRP process if RI Energy is the sole entity that makes the final recommendations for approval by the PUC. A strong, independent process monitor and/or program administrator may be necessary to help avoid conflicts of interest in the utility's recommendations to the PUC. Given the financial and regulatory incentives that inform investor-owned utility investment decisions in general, it is possible that a utility, when considering NWA and NPA, could be biased towards recommending its own investment bid as the best solution to meet a grid need, potentially overlooking and omitting competitive NWA and NPA bids from third-party developers in its recommendations to the PUC. An independent process monitor can play an important role as watchdog and can help ensure that the process is competitive and does not result in unintended consequences or biases within the evaluation process. A neutral process monitor may also be able to settle potential disputes over the application of certain solution evaluation criteria. For example, there may be disagreements over Rhode Island Energy's evaluation of whether a third-party proposal is "environmentally responsible" or not compared to a traditional utility solution, and a process monitor could help address potential conflicts of interest. An independent process monitor may also offer a mechanism of accountability for ensuring that systems needs data made available to third parties is sufficiently comprehensive and timely.

Connecticut's Non-Wires Solutions (NWS) program may offer useful lessons for the SRP process. When designing the NWS program in Connecticut, PURA considered potential conflicts of interest on the part of its investor owned utilities (IOUs) to be strong enough that it chose to establish a neutral NWS process monitor that was "fully independent of the [electric distribution companies] and other stakeholders."[3] As structured within Connecticut's NWS program, the process monitor provides oversight over the solicitation process, and the utilities and the process monitor receive third-party bids to review at the same time. As part of the annual NWS process, the process monitor assesses the RFP process, submits its own independent evaluation of the electric distribution companies' (EDC) recommendation for each NWS solicitation, and comments on any real or perceived conflicts of interest. PURA then reviews both recommendations and allows for public comment before making a final decision. The NWS program includes four categories of allowed projects: 1) the traditional EDC investment that would have been made without the NWS program; 2) an alternative EDC investment bid for a project that the utility would own; 3) a non-EDC, third-party developer bid made in response to competitive RFP; and 4) EDC-third party partnership bids where the EDC and a third-party solution provider work together to develop a proposal. For projects in which an EDC or an EDC affiliate proposes an NWS bid, the process monitor evaluates the bid itself and submits a recommendation to PURA.[4]

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[3] PURA Docket No. 17-12-03RE07, Final Decision, Appendix A – Non-Wires Solutions Process Design Document, November 9, 2022, at 7.

[4] PURA Docket No. 17-12-03RE07, November 9, 2022 Order, at 36 and 37.

Within RI Energy's proposed SRP process, Acadia Center would appreciate more detail about which utility staff members will serve on the SRP proposal evaluation committee. Further, Acadia Center encourages RI Energy to acknowledge any real or perceived conflicts of interest inherent in the utility-run process and to cooperate with the engagement of an independent process monitor and evaluator in the SRP process.

### Avoid the Unintended Risks of Gaming

Acadia Center recommends that RI Energy take care to address potential risks of gaming within the SRP process. For example, while the SRP proposal refers to a $1 million threshold for consideration of non-wires alternatives, it may be tempting to, for example, split a single $1.2 million project into two $600k projects so that the NWA threshold is not triggered. Connecticut's Non-Wires Solutions program offers a method for overcoming this potential risk by requiring the electric distribution companies (EDCs) to include several categories of investments in their annual grid needs filings. These are: "likely" NWS solicitation opportunities that are projected to cost $1 million or more; "potential" opportunities between $500k-$1 million; and "unlikely" opportunities between $250k-$500k.[5] Acadia Center invites RI Energy to consider presenting SRP solicitation opportunities as similar categories of investments in its annual system needs reporting to the PUC. This voluntary step would offer an additional layer of data transparency and helpful remedy to the unintended risks of gaming.

Thank you for the opportunity to submit these comments. Acadia Center looks forward to engaging in this process.

Sincerely,

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[5] PURA Docket No. 17-12-03RE07, November 9, 2022 Order, at 28.

## EXHIBIT A – REQUIREMENTS FOR ANNUAL EDC DATA FILING

Baseline Distribution System, Financial, and DER Deployment Data and Information
To be submitted annually on February 8th by the EDC to the NWS Process

### System Data

1. Annual peak load growth at the most granular level available, i.e., the circuit, substation, town, operating area, or system level for each of the past five years and forecasted load growth for each of the next ten years.
2. Distribution system load forecast for all circuits, including circuit capacity, and including, where available, historic (past three years) and forecast (both the next three and five years) loading for maximum peak day and minimum day.
3. Projected voltage and power quality impacts from distributed energy resources (DER) at the substation-level.
4. Discussion of how DER, and at what level DER is considered, in load forecasting (e.g., distribution feeder, sub-transmission level, distribution substation, bulk distribution substation level, or system-wide) and any expected changes in load forecasting methodology.
5. Most recent distribution system annual loss percentage for the prior year (system-wide and by circuit, where available).
6. The maximum hourly coincident monthly load, in kilo-volt-ampere (kVA), for the distribution system, in the past 12 months, as measured at the interface between the transmission and distribution system. Indicate if calculated using SCADA data or interval metered data or other non-billing metering / monitoring systems.
7. Total distribution substation transformer nameplate in kVA.
8. Total distribution line transformer nameplate in kVA.
9. *(Potential Partial Redaction)* List and map of distribution substation transformers (which feed only distribution level customers) that are:
    a. 90-100% within their normal rating;
    b. 80-90% within their normal rating; and
    c. Less than 80% of their normal rating
10. *(Potential Partial Redaction)* A list of all distribution feeders broken down by distribution feeders that are:
    a. 90-100% within their normal rating;
    b. 80-90% within their normal rating; and
    c. Less than 80% of their normal rating.
11. Utility-wide System Average Interruption Duration Index (SAIDI), System Average Interruption Frequency Index (SAIFI), Customer Average Interruption Duration Index (CAIDI) excluding and including major storms for the past three years.
12. Ranking of circuits according to tiers 1, 2, and 3 in the “Worst-Performing Circuits 2.0” program for the past three years outlined by the Authority in the 17-12-03RE08 Decision. Due to the new implementation of that program, three years

of data may not be available immediately. Until that information is available for all three years, the EDCs may supplement missing data with contribution to SAIDI and SAIFI including and excluding major storms.

13. Number of separately metered electric vehicle level 2 and level 3 (i.e., direct current fast charging or DCFC) charging systems added to the Company's distribution system over each of the past three years.
14. Number of level 2 and level 3 electric vehicle charging systems currently forecasted to be installed annually in the next three to five years.

**Financial Data**

1. Historical distribution system spending for the past 10-years, in each category:
    a. Age-Related Replacements and Asset Renewal;
    b. System Expansion or Upgrades for Capacity;
    c. System Expansion or Upgrades for Reliability and Power Quality;
    d. New Customer Projects and New Revenue;
    e. Grid Modernization and Pilot Projects;
    f. Government Mandates;
    g. Metering;
    h. Other.
2. Current 5-year Capital Plan.
3. Documentation for planned distribution capital projects for reliability/capacity/resilience/power quality/interconnection projects exceeding cost of $250,000 including:
    a. Justification/drivers for the project (e.g., see categories listed under Financial Data No. 1);
    b. Timeline for improvement;
    c. Estimate of project cost;
    d. Project scope and key materials (e.g., transformer, etc.);
    e. Identification of project risks (e.g., potential for delays or cost overruns).
4. Disclose all Unknown Priority Investments over $250,000 from prior years, including:[28]
    a. Justification/drivers for the project (e.g., see categories listed under Financial Data No. 1);
    b. Timeline for improvement;
    c. Estimate of project cost;
    d. Project scope and key materials (e.g., transformer, etc.);
    e. Identification of project risks (e.g., potential for delays or cost overruns).

[28] The Authority expects that projects completed in the same calendar year that are related, on the same substation or circuit, will be considered together—that is, with a total budget for all related distribution system investments—for purposes of this disclosure threshold.

5. Provide a retrospective analysis of NWS implemented in prior years, including an accounting of their actual costs and the realized benefits.
6. Provide the most up-to-date information on the metrics included in the EM&V plans for each NWS currently in service.

**DER Deployment**

1. Current distributed generation deployment by type (photovoltaic, hydro, wind, etc.), size ((1) 0 kW to 25 kW, (2) more than 25 kW to 200 kW, (3) more than 200 kW to 600 kW, (4) more than 600 kW to 2,000 kW, and (5) more than 2,000 kW), and geographic dispersion (as useful for planning purposes; such as, by planning areas, service/work center areas, cities, etc.).
2. Projected distributed generation deployment by type (photovoltaic, hydro, wind, etc.), size (≤100 kilowatt ("kW"), 100kW-1 megawatt ("MW"), >1MW), and geographic dispersion (as useful for planning purposes; such as, by planning areas, service/work center areas, cities, etc.) over the next three and five years, respectively.
3. Information on areas with existing or forecasted transient voltage or frequency issues that may benefit from the utilization of advanced inverter technology, energy storage systems, or NWS more broadly; provide information describing experiences where distributed generation installations have caused operational challenges such as power quality, voltage or system overload issues, and associated customer complaints.
4. Provide currently available Hosting Capacity Maps for all measures of Hosting Capacity.