The Rhode Island Energy Efficiency and Resource Management Council (EERMC)

March 1, 2011

Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02888

RE: System Reliability Procurement Standards – Recommendations

Dear Commissioners Germani, Bray, and Roberti

By way of this letter and its attachment, the Energy Efficiency and Resource Management Council, ("EERMC") respectfully submits to the Commission its recommendations with regard to the System Reliability Procurement Standards (SRP). Pursuant to R.I.G.L. § 39-1-27.7(c)(1), the EERMC recommends making significant revisions to the System Reliability Procurement Standards in order to establish a robust procedure and funding options for systematically identifying customer-side and distributed resources that, if cost-effective, defer or avoid distribution upgrades and improve system reliability, in accordance with the objectives of R.I.G.L.§ 39-1-27.

The EERMC recommends the attached revisions to the System Reliability Procurement Standards found in Appendix A and respectfully requests the Public Utilities Commission to consider these recommendations. Because the proposed changes to the currently approved Standards are significant they are presented as a complete rewrite of the SRP Standards.

A brief review of the legislative background and recent procedural history concerning the SRPP is in order.

Legislative Background

The 2006 Act identified a unique opportunity for Rhode Island to systematically identify and procure customer-side opportunities that were not only cost-effective compared to traditional supply options, but that might also provide a cost-effective path to lower supply and delivery costs to ratepayers in Rhode Island. If distribution system investments could be deferred, then the program might provide savings over time for customers and might lower the volatility and cost uncertainty of the larger energy and capacity markets in New England by securing sources of energy supply and capacity from in-state resources.

Traditionally, the solutions to problems such as overloaded facilities, low voltage, stability response, contingencies, loss of load, asset condition, and system losses have been provided by capital projects that enhance the utility's delivery systems: new circuits, new substations, or larger conductors. As developing technologies continue to make improvements in energy efficiency, load management, and distributed generation, the range of possible alternative solutions to traditional utility infrastructure can now increasingly consider demand side management, demand response, direct load control, distributed generation, and dynamic pricing. As technologies and markets continue to mature and gain momentum, these "non-wires alternatives" (NWAs) are becoming increasingly cost-effective. Recognizing the potential economic benefits of cost-effective NWAs, R.I.G.L § 39-1-27.7 (a) (1) calls for "system reliability" resources examined to include, but not be limited to: distributed renewable energy resources; cost-effective combined heat and power systems; and demand response designed to provide local system reliability benefits through load control or using on-site generating capacity.

Recent Procedural History

In June, 2008 the Public Utilities Commission issued an order approving "Standards for Energy Efficiency and Conservation Procurement and System Reliability." Chapter 2 Sec. 2.1 of the Standard directs National Grid ("the Company ") to propose pilot distribution and, if appropriate, transmission projects in a system reliability procurement plan for which it shall examine customer side resources as alternatives or enhancements to the distribution or transmission upgrade. Customer side resources to be examined in the plan include distributed generation generally; combined heat and power; renewable energy (predominately wind and solar); demand response; and peak demand and geographically focused energy efficiency programs.

At an Open Meeting on October 20 2008, the Commission deferred its decision on the Company's Least Cost Procurement Plan and System Reliability Procurement Plan. The decision to defer was based in part on comments submitted by the Division of Public Utilities Carriers ("Division"), the Office of Energy Resources (OER), and The Energy Council of Rhode Island (TEC-RI) noting that there was insufficient background in the SRPP to allow those parties to establish and set forth their positions. In December of the same year, the Division recommended approval of the SRPP plan with conditions: 1) the time period of funding would be for a one year trial period; 2) a process would be established to assess the program's cost-effectiveness and possibly modify the measure mix for the Aquidneck Island pilot, and: 3) a commitment would be made to minimize the cost of any renewable technologies implemented as part of the pilot. The Aquidneck Island pilot was to evaluate the capability of alternative customer side resources to address loading issues on the electric distribution system.

The EERMC also supported conditional approval, and understood that the pilot would be a way to determine the consistency and costs of this type of load relief, and therefore the value of these customer-side resources to the distribution system. In March 2009 the Commission approved the Company's SRPP for a three year period but deferred any decision regarding program funding until it had been determined whether excess funds were recovered from the Energy Efficiency Procurement Plan, in which case the excess funds would be used to offset the funding of the SRPP.

In the summer of 2009, after the Department of Energy (DOE) stimulus funds for Smart Grid were announced, the Governor of RI requested National Grid submit a Smart Grid pilot within the state of RI to attempt to gain access to some of the stimulus funds that could be used for up to a 50% match towards the cost of a Smart Grid pilot. National Grid elected to expand the footprint for the proposed Aquidneck Island pilot for its Smart Grid filing. While this effort was underway, any work to find a funding source for the SRPP was suspended.

National Grid subsequently was notified that the RI Smart Grid pilot did not secure matching funds from the DOE.

Recent System Reliability Activity and Proposal

Over the past 18 months, the Council has developed a process for revising the system reliability procurement standards and a framework for considering NWAs as possible solutions to planning and reliability issues. The Council understands that the objective is to establish a procedure and funding options for systematically identifying customer-side and distributed resources that, if cost-effective, defer or avoid distribution upgrades, improve system reliability, and provide for better utilization of distributed resources. The goal is also to effectively anticipate new technologies (such as electric vehicles and energy storage) and become a model for other states and utilities.

The Council recommends revisions to the System Reliability Procurement Standards with the intent of providing clear guidelines for a planning process that considers both traditional and non-wires alternatives to planning and reliability issues. The recommendations for revising the System Reliability Procurement Standards (Appendix A) are designed to guide the Company in fully integrating analysis of non-wires alternatives into the Company's planning functions and evaluating the specific costs, benefits, and comparability of traditional and non-wires solutions.

The Company has undergone an impressive internal planning process to incorporate the consideration of NWA options into its Distribution and Transmission planning. This procedure has been approved by the Company for its own use. The recommended Standards utilize the Company's procedure in many areas.

The proposed revisions to the Standards outline a process in which the Company, the Council, and the Council's consultant will continue to work with state regulators and other stakeholders to further our collective understanding of non-wires alternatives. This will include the development of more sophisticated analytical tools, development of appropriate evaluation criteria, and potentially, proposing pilot installations of cost-effective non-wires alternative solutions. The revisions to the Standards establish a process that enables an objective assessment of the alternatives as the Company integrates the analysis of non-wires alternatives into distribution planning, as required by R.I.G.L. § 39-1-27.7.

The EERMC recommends the revisions to the System Reliability Procurement Standards found in Appendix A.

Respectfully Submitted,

THE RHODE ISLAND ENERGY EFFICIENCY AND RESOURCE MANAGEMENT COUNCIL

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CERTIFICATE OF SERVICE

I hereby certify that on the 24st day of February, 2011, I delivered a true copy of the foregoing document either by first class mail or by electronic mail to the Rhode Island Public Utilities Commission as required by R.I.G.L.§ 39-1-27.7(c)(1).

/s/ R. Daniel Prentiss

R. Daniel Prentiss

Attachment A:

EERMC's Recommended Technical Amendment to the System Reliability Procurement Standards

1. Strike all existing language in Chapter 2 and replace with the following:

Chapter 2- System Reliability Procurement

Section 2.1 Distributed/Targeted Resources in Relation to T&D Investment

A. The Utility System Reliability Procurement Plan ("The SRP Plan") to be submitted for the Commission's review and approval on September 1, 2011 and triennially thereafter on September 1, shall propose general planning principles and potential areas of focus that incorporate non-wires alternatives (NWA) into National Grid's ("the Company") distribution planning process for the three years of implementation beginning January 1 of the following year.
B. Non-Wires Alternatives (NWA) may include but are not limited to:
    a. Least Cost Procurement energy efficiency baseline services.
    b. Peak demand and geographically-focused supplemental energy efficiency strategies
    c. Distributed generation generally, including combined heat and power and renewable energy resources (predominately wind and solar, but not constrained)[1]
    d. Demand response
    e. Direct load control
    f. Energy storage
    g. Alternative tariff options
C. Identified transmission or distribution (T&D) projects with a proposed solution that meet the following criteria will be evaluated for potential NWA that could reduce, avoid or defer the T&D wires solution over an identified time period.
    a. The need is not based on asset condition.

[1] In order to meet the statute's environmental goals, generation technologies must comply with all applicable general permitting regulations for smaller-scale electric generation facilities.

b. The wires solution, based on engineering judgment, will likely cost more than $1 million;
c. If load reductions are necessary, then they are expected to be less than 20 percent of the relevant peak load in the area of the defined need;
d. Start of wires alternative is at least 36 months in the future; and

A more detailed version of these criteria may be developed by the distribution utility with input from the Council and other stakeholders.

D. Feasible NWAs will be compared to traditional solutions based on the following:
   a. Ability to meet the identified system needs;
   b. Anticipated reliability of the alternatives;
   c. Risks associated with each alternative (licensing and permitting, significant risks of stranded investment, sensitivity of alternatives to differences in load forecasts, emergence of new technologies)
   d. Potential for synergy savings based on alternatives that address multiple needs
   e. Operational complexity and flexibility
   f. Implementation issues
   g. Customer impacts
   h. Other relevant factors

E. Financial analyses of the preferred solution(s) and alternatives will be conducted to the extent feasible. The selection of analytical model(s) will be subject to Public Utilities Commission review and approval. Alternatives may include the determination of deferred investment savings from NWA through use of net present value of the deferred revenue requirement analysis or the net present value of the alternatives according to the Total Resource Cost Test (TRC). The selection of an NWA shall be informed by the considerations approved by the Public Utilities Commission which may include, but not be limited to, those issues enumerated in (D), the deferred revenue requirement savings and an evaluation of costs and benefits according to the TRC. Consideration of the net present value of resulting revenue requirements may be used to inform the structure of utility cost recovery of NWA investments and to assess anticipated ratepayer rate and bill impacts.

F. For each need where a NWA is the preferred solution, the distribution utility will develop an implementation plan that includes the following:
   a. Characterization of the need
      i. Identification of the load-based need, including the magnitude of the need, the shape of the load curve, the projected year and season by which a solution is needed, and other relevant timing issues.

ii. Identification and description of the T&D investment and how it would change as a result of the NWA
iii. Identification of the level and duration of peak demand savings and/or other operational functionality required to avoid the need for the upgrade
iv. Description of the sensitivity of the need and T&D investment to load forecast assumptions.

b. Description of the business as usual upgrade in terms of technology, net present value, costs (capital and O&M), revenue requirements, and schedule for the upgrade
c. Description of the NWA solution, including description of the NWA solution(s) in terms of technology, reliability, cost (capital and O&M), net present value, and timing.
d. Development of NWA investment scenario(s)
    i. Specific NWA characteristics
    ii. Development of an implementation plan, including ownership and contracting considerations or options
    iii. Development of a detailed cost estimate (capital and O&M) and implementation schedule.

G. Funding Plan

The Utility shall develop a funding plan based on the following sources to meet the budget requirement of the system reliability procurement plan. The Utility may propose to utilize funding from the following sources for system reliability investments:

i. Capital funds that would otherwise be applied towards traditional wires based alternatives;

ii. Existing Utility EE investments as required in Section I of these Standards and the resulting Annual Plans.

iii. Additional energy efficiency funds to the extent that the NWA can be shown to pass the TRC test with a benefit to cost ratio of greater than 1.0 and such additional funding is approved;

iv. Utility operating expenses to the extent that recovery of such funding is explicitly allowed;

v. Identification of significant customer contribution or third party investment that may be part of a NWA based on benefits that are expected to accrue to the specific customers or third parties.

vi. Any other funding that might be required and available to complete the NWA.

H. Annual SRP Plan reports should be submitted on November 1. Such reports will include but are not limited to:
   a. A summary of projects where NWA were considered;
   b. Identification of projects where NWA were selected as a preferred solution; and a summary of the comparative analysis following the criteria outlined in sections (D) and (E) above;
   c. Implementation plan for the selected NWA projects;
   d. Funding plan for the selected NWA projects;
   e. Recommendations on pilot distribution and transmission project alternatives for which it will utilize selected NWA reliability and capacity strategies. These proposed pilot projects will be used to inform or revise the system reliability procurement process in subsequent plans;
   f. Status of any previously selected and approved projects and pilots;
   g. Identification of any methodological or analytical tools to be developed in the year;
   h. Total SRP Plan budget, including administrative and evaluation costs.

I. The Annual SRP Plan will be reviewed and funding approved by the Commission prior to implementation.