nationalgrid

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VIA ELECTRONIC MAIL

Rhode Island Power Sector Transformation Initiative
c/o Rhode Island Division of Public Utilities and Carriers and Office of Energy Resources
DPUC.powertransformation@dpuc.ri.gov

RE: Rhode Island Power Sector Transformation Initiative
Request for Stakeholder Comments on the Draft Recommendations
National Grid's Comments

Dear Members:

On behalf of National Grid,[1] I enclose the Company's comments in response to the draft recommendations outlined in the request dated October 16, 2016 from the Division of Public Utilities and Carriers, the Office of Energy Resources, and the Public Utilities Commission (PUC), and discussed at the PUC offices on October 23, 2017.

The Company looks forward to future discussions on this important topic. If you have any questions, please contact Kayte O'Neill at 781-907-1790, Tim Roughan at 781-907-1628, or me at 401-784-7288.

Very truly yours,

Jennifer Brooks Hutchinson

Enclosure

[1] The Narragansett Electric Company d/b/a National Grid (National Grid or the Company).

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Public Utilities Commission, Division of Public Utilities and Carriers, and
Office of Energy Resources

Power Sector Transformation

National Grid's Comments on October 13, 2017 Draft Rhode Island Power Sector Transformation Report

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National Grid appreciates the opportunity to submit written comments on the draft Rhode Island Power Sector Transformation (PST) Report (Draft Report) released to stakeholders on October 16, 2017, and discussed at the Rhode Island Public Utilities Commission (PUC) offices on October 23, 2017. National Grid has welcomed the opportunity to provide feedback to the PUC, the Rhode Island Division of Public Utilities and Carriers (Division), and the Rhode Island Office of Energy Resources (OER) in the context of their efforts to develop for Governor Raimondo a package of PST regulatory frameworks, proposals, or deployment strategies, as appropriate, pursuant to her March 2, 2017, correspondence to the agencies.

As was discussed at the October 23, 2017 PST stakeholder meeting, National Grid is in the latter stages of preparing a request to the PUC for approval of new base distribution rates, which will include several PST initiative proposals. The Company is pleased that a large part of its upcoming PST initiative proposal appears to be directionally consistent with many of the initiatives addressed in the Draft Report (e.g., beneficial electrification initiatives, electric vehicles, performance metrics). National Grid will provide a comprehensive PST plan in its upcoming rate filing describing the proposals in detail and noting alignment in several areas with the principles and recommendations included in the Draft Report.

Upon review of the Draft Report, however, there are several instances where National Grid seeks reconsideration of some draft recommendations, and some draft language providing inaccurate context for such recommendations, as addressed below.[1] In addition, the Company takes the opportunity to reiterate in these comments a few issues addressed in the Company's previous PST stakeholder comments (on September 8 and 12, 2017, respectively) prior to the efforts by the PUC, Division, and OER to finalize the report to Governor Raimondo.

1) **The Utility Business Model (UBM) Principles and Recommendations Unfairly Conclude That the Utility Compensation Framework Needs Reform.**

Of all the topics addressed in the Draft Report, the draft conclusions in the UBM Principles and Recommendations are the most concerning because many are based on inaccurate or misleading premises. The Company addresses several issues with this module from the Draft Report below:

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1 The Company has not addressed each and every recommendation in the Draft Report in these comments. Rather, the Company is focusing its comments on particular draft recommendations and, in some instances, the context of those draft recommendations, in order to provide PST stakeholders with feedback from the Company in the near term on what it has identified as key areas of interest to the Company.

<u>The Draft Report Inaccurately Concludes that the Company's Electric Distribution Business Has Over-Earned During 2014 and 2015</u>

The UBM module of the Draft Report states that, in calendar years 2014 and 2015, National Grid in Rhode Island reported earnings to shareholders that met or exceeded its allowed return on equity (ROE) for both its electric and gas distribution businesses (UBM Draft Report at 7). However, this is not an accurate way to portray the Company's reported earnings. As noted in the Company's recent annual electric earnings reports filed with the PUC, in each year, the Company's reported earnings were *below* its allowed returns.

In addition, the comparison of earnings reported to shareholders and those reported in regulatory reports misrepresents the Company's allowed earnings for those years. The Company's earnings reports to the PUC include *both* earnings with and without energy efficiency performance incentives. In comparison, at the request of the Division, the Company provided information for purposes of the Draft Report comparing its actual earnings including energy efficiency performance incentives to allowed earnings. The Company was not asked to compare its actual earnings to allowed earnings without energy efficiency performance incentives. The latter provides a more accurate comparison of the Company's actual-to-allowed earnings. The Company is allowed to keep energy efficiency performance incentives as a tradeoff for earning revenue from electric sales, which energy efficiency has been successful in reducing. Accordingly, observations drawn in the Draft Report regarding the Company's earnings need to be revised to provide a more accurate assessment of the Company's financial status before drawing any conclusions about potential changes to utility compensation.

<u>The Company Does Not Have a "Bias" Toward Building Infrastructure</u>

The characterization in the UBM Draft Report that electric utilities have an inherent "infrastructure bias" unfairly implies that the Company is subject to the same proclivities (<u>see</u> UBM Draft Report at 3). On the contrary, the Company's actual history in Rhode Island leads to a different conclusion. First, as noted in the Company's September 8, 2017 comments submitted to PST stakeholders, the discussion overlooks the regulatory obligation of the Company to have the infrastructure in place to serve customer-driven peak loads safely and reliably and the underlying economic and weather considerations that encourage customers to use electricity in the patterns observed. Finally, this draft conclusion ignores the significant efforts that the Company has already undertaken, and is continuing to develop, to engage customers in demand response and reduce peak demand. Further, the Company has a long history of making investment and operational decisions to the benefit of customers under the current regulatory framework. Regulatory oversight of capital and operating expenditures ensures their prudency, thus requiring the Company to demonstrate alignment with customer interests and regulatory standards. Accordingly, the draft conclusions about a "bias" toward infrastructure investment, without a more comprehensive discussion about the regulatory context for investment decisions, provides a misleading context for potential future regulations and should be revised.

That said, the Company has recognized throughout this proceeding that the current regulatory framework can create a disincentive for utilities to take on the risk associated with innovation, and may not sufficiently align utility interests with broader policy goals or desired customer outcomes that expand beyond the utility's core performance obligations. To that end, the Company agrees there is value in exploring how reforms, such as the development of new utility performance incentives, can align utility interests with state policy objectives and generate new benefits for customers.

Although the Company Supports Inclusion of Potential Performance Incentives in its Overall Compensation, They Must Not Be Deemed a Substitute for an Approved ROE

The Company's allowed ROE is an important signal to investors and credit ratings agencies. An adequate authorized ROE is essential to the Company's ability to raise capital at a reasonable cost and on reasonable terms. Particularly in the early years of performance incentive mechanisms (PIMs), there is likely to be significant uncertainty involved in the definition of appropriate metrics, setting of targets, and determining the potential earnings levels at given targets, making it difficult to calibrate expected (as opposed to potential) earnings from PIMs to a level that would offset a given reduction in ROE. A lower authorized ROE combined with uncertain incentive earnings has the potential to increase the Company's risk profile, and could potentially put the Company at risk of credit downgrades, ultimately to the detriment of customers.

Any contemplation of adjustments to the authorized ROE in the presence of new incentives needs to evaluate the full portfolio of potential upside and downside incentives. The presence of downside incentives in this portfolio, for example, has not, to the Company's knowledge, led to contemplation of an offsetting increase in the authorized ROE. The Company suggests that the potential value of new incentive earnings opportunities would have to be substantially more than any corresponding reduction in ROE in order to maintain the requisite investor confidence.

As an alternative to an ROE adjustment, a more beneficial approach would be to include an earnings sharing mechanism that will ensure that total earnings (ROE + PIMs) do not exceed a certain level, with excess earnings shared with customers as they are today.

The Company considers any definitive statement regarding a move to a "total expenditure" cost recovery model, as contemplated with the Draft Report, as premature. The PUC and interested stakeholders need to fully evaluate and consider the implications of any alternative cost-recovery models with respect to the objectives they aim to achieve as well as potential unintended consequences on utility operations. In undertaking such evaluation, the PUC should consider how the objectives of a 'total expenditure' model could be met through incremental, measured refinements to the existing model in order to optimize between the benefits to be gained for customers and the 'regulatory lift' required to transition to a full total expenditure model.

Changes to Rate Case Filing Requirements are Not Warranted.

Finally, the Draft Report recommends that the Company file a three-year Business Plan covering all initiatives and costs over a three-year period (including ISR, SRP, etc.). However, the legal, regulatory, and operational impacts of such a recommendation are significant and require more analysis. Until such time in the future when this issue can be addressed in more detail, the Company will continue the development of its base distribution rate filing for presentation to the PUC in the next several weeks.

2) The Company Agrees With the Draft UBM Recommendation Regarding the Exploration of Partnership Models.

The Draft Report addresses several areas where the Company may seek to leverage PIMs, in combination with existing capabilities, to develop new initiatives to advance intelligent infrastructure (UBM Draft Report at 23). As noted in the Company's September 8, 2017 comments submitted to PST stakeholders, the Company agrees with the Division that there is value in exploring new partnership models to advance development of intelligent infrastructure to support development of new system and customer benefits. The Company is working to evaluate how such partnerships could be implemented in a manner that delivers maximum value to our customers over an expeditious timeframe.

National Grid has a long history of working with vendors in order to be able to access specific capabilities and resources that the Company is not able to cost-effectively provide, but that benefit our customers. Of course, the Company understands the Innovative Partner Models being considered by the Division represent greater partner involvement than might occur under a traditional vendor-customer relationship. For example, the partner to the utility might be expected to contribute capital or take on some level of risk, with the goal of ultimately providing new services and opportunities to customers at a lower cost than might otherwise occur if the Company were to undertake such investments independently. With these considerations in mind, the Company has begun to consider how partnerships might appropriately be structured in the areas below in order to most effectively benefit customers. As noted in prior comments, the Company suggests that the Division consider the following points in evaluating the potential partnership models:

- Partnerships with third parties should be designed to maximize net benefits to customers through the outcomes achieved and the combination of revenue sharing and any cost-sharing on the part of third parties.

- Potential incremental earnings to the utility from any partnership should be commensurate with the level of risk borne by shareholders.

- Specific system needs will likely limit the ability of the Company to engage in a partnership, particularly where reliance on partner performance might impact the reliability and safety of the electric distribution system.

- Development of potential partnerships must address potential interactions with existing regulations governing utility procurement as well as utility standards of conduct.

3) **The Distribution System Planning (DSP) Draft Report Provision Recommending Coordinated DSP Filings Ignores the Sequencing Necessary to Develop the Company's System Reliability Procurement (SRP) Plan and Infrastructure, Safety, and Reliability (ISR) Plan.**

The DSP Draft Report states that the SRP and ISR plans represent critical and complementary areas of utility investment, and concludes that the PUC and stakeholders should be able to consider investments made in both these processes in an integrated manner (DSP Draft Report at 8). However, this draft recommendation ignores the independent purposes of the SRP and ISR plans, and the resulting sequencing necessary to develop these plans. To inform the selection of projects proposed for the ISR plan, the Company, through DSP, forecasts loads, identifies distribution system needs, and proposes infrastructure or NWA solutions. Accordingly, the Company develops these plans at different intervals, typically 1-3 years apart, because the SRP plan (or non-wires) investments must be analyzed during or at the end of a localized planning study, which must focus in the first instance on identifying possible "wires" alternatives to meet the Company's obligation to provide safe and reliable electric service to customers. The development of "wires" projects must take priority because these types of projects are known and proven solutions to address system reliability, system condition and/or system operational needs. Once the identification of "wires" alternatives is completed, the analysis of "non-wires" alternatives can then be performed to determine if such non-wires options can meet the same goals as the "wires" alternative in providing safe and reliable distribution service at a lower cost to customers. In addition, in the event a non-wires project delivers less load relief than needed, the Company must stand ready to deliver a wires solution in short order if need be, and thus parallel development of the wires solution must occur.

In Rhode Island, the Company has 11 different planning areas that are rotated every 5-8 years to determine what the Company's long term (15 year) loads/system condition may be at the end of that term. This analysis allows the Company to better determine potential capital investment changes it may need to implement in that time horizon. Once the Company determines those investments, and based on the Company's overall infrastructure improvement needs and allowed budget, it includes them in its annual ISR plans for potential future implementation.

Because of the difference in time when a non-wires option is developed and when a project is selected for inclusion in an annual ISR Plan (approximately 1-3 years in most cases), it would be challenging for the PUC to consider investments in both of these processes in an integrated manner as recommended in the Draft Report. Nonetheless, the Company acknowledges these investments complement each other. Thus, one option could be that, if a non-wires proposal moves forward, the Company could include reference to that project in a future ISR plan filing, and mention that the equivalent wires solution of a certain amount is, therefore, being excluded from the filing. In addition, as is already done in the SRP plan filing, the Company could include a discussion of the equivalent wires solution. As the SRP plan process now includes looking at hybrid non-wires opportunities (i.e., some of the need is met with a smaller wires investment, and the remainder met with a non-wire option), reference in both filings would be made to reflect how the Company is meeting the total need in an area. This requires an understanding that the discussion of the corresponding wires solution that a non-wires investment could replace, either in full or partially, which is included in an SRP plan filing, would not be seen in an ISR plan for 1-3 years later

4) **With Regard to the Grid Connectivity and Meter Functionality (GCMF) Draft Report, the Company has Been Actively Researching Issues Associated with Third-Party Access to Company Advanced Metering.**

The GCMF Draft Report addresses several issues associated with the deployment of advance meters. The Company's upcoming PST initiative proposal will provide an assessment of the potential costs and benefits of advanced meter deployment in Rhode Island. In the meantime, the Company wishes to restate in these comments its efforts to research issues specifically associated with third-party access to advanced metering.

As noted in the Company's September 12, 2017 PST stakeholder comments, National Grid is actively researching opportunities and challenges associated with a multi-user shared network operation model through three different venues: 1) research from a major telecommunications provider; 2) a venture capitalist that has reached out to the Company; and 3) a collaborative forum being established by PST leadership.

Based on the Company's research thus far, there are four important challenges to the development of a multi-user network operating model that must be addressed. The first is finding a model or development model that can be successfully deployed while demonstrating lower communication costs for the end-user.

The second challenge that must be addressed is cybersecurity. A shared network must support the Company's obligation to provide for a safe, secure, and reliable energy delivery system. Introducing a multi-user network could pose additional cybersecurity risks that could impact distribution and transmission utility operations. There will be mission-critical aspects of distribution and transmission utility operations where it may not be prudent to use a shared network if cybersecurity issues cannot be clearly and efficiently addressed.

The third challenge is the allocation of administrative and technical ownership and accountabilities. For example, which party should administrate service levels, costing, security, the network operation center, system configuration, and other relevant factors? Should it be the party with the biggest risk? Should this party be a regulated entity?

The fourth challenge is any restrictions posed by utility regulation or the Telecommunications Act of 1996. The Act was the first comprehensive rewrite of the Communications Act of 1934 and dramatically changed the ground rules for competition and regulation in virtually all sectors of the communications industry, from local and long-distance telephone services, to cable television, broadcasting, and equipment manufacturing.

In conclusion, the Company looks forward to continued engagement with the PST stakeholders, and respectfully requests that the Division, OER, and PUC consider the above comments in preparation of the final PST Report that will be submitted to Governor Raimondo pursuant to her March 2, 2017 letter to the agencies.