Memorandum
From: Seth Handy
To: Jonathan Schragg
Date: September 8, 2017
Regarding: Rhode Island Division of Public Utilities and Carriers & Office of Energy Resources Power Sector Transformation Supplemental Q&A on Utility Compensation

I respond on behalf of Handy Law. Many of the supplemental questions raised here were also addressed in our initial comments, which have not been repeated here (with some small and seemingly appropriate exceptions).

Questions for Discussion and Additional Stakeholder Comment

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1. Please provide any recommendations related to the components of the multiyear rate plan described on page 6 of this document.

   Reply: We provided a general response regarding MRPs in our initial comments.

   - *Rate case moratorium*: We support an eight year moratorium based on a stakeholder developed Integrated Resource Plan that reduces overall system costs, increases grid reliability and resiliency, and fosters customer engagement and including an earnings share mechanism and monitored results. The plan should address protections against deterioration of plant and oversight. It should include a PUC reopener for unforeseen circumstances (eg, taxes, interest rates). Open access to information is a critical element of monitoring performance on the plan. Transition to an IRP model should occur through incremental steps that are guided by a clear set of long-term goals and objectives. Emphasis should be placed on developing the regulatory and system platforms that support innovation while providing the appropriate level of protections to consumers. Because technology as well as service and product innovation are at the heart of the distributed grid, it will be important for the Commission to remain focused on framing the vision and the regulatory incentives. The Commission should enable the risk and reward mechanisms that enable innovation without trying to select the winning technology or products. At the same time, it will be critical to take the first tangible steps that will drive change and long-term value.
   - *Attrition relief mechanism*: We are not clear on why the presumption of growing revenues (despite attrition in service levels) appears to be

reiterated in all options. If utility compensation is an important element of the cost of our energy system to customers and utility profits have steadily climbed throughout history along with inclining electric rates, why should growing revenues be presumed with reduced levels of service? Isn't it a regulatory function to ensure that the monopoly utility is functioning for the benefit of its customers with a reasonable return based on the level of service provided? We subscribe to forecast-based revenues derived from a stakeholder-reinforced integrated resource plan to reduce all costs including utility compensation.

- *Cost trackers*: Why does the utility need to be paid to fulfill functions that benefit its customers? Isn't that its intended and regulated function? If those incentives are an element of expense to customers is there a way to sunset them (i.e., incentives to change monopoly's unregulated behavior become regulated expectations)?
- *Earnings sharing mechanis*m: How much of this planning mechanism needs to be supported by incentive and how much can be expected/regulated as a result of a stakeholder-endorsed and approved planning process?
- *PIMs to prevent service degradation*: These would have to be evaluated based on the specific nature of the referenced "productivity pressure." This also comes back to the question of whether such matters of system reliability and customer service should be regulatory expectations or should require incentives. If incentives are needed to change behavior, why shouldn't they sunset and convert to regulatory expectations eventually?
- *PIMs to achieve goals and shift utility incentives*: We support these PIMs if/as truly needed to supplement regulatory authority/expectation. It seems important to understand the term of the incentive and to always balance regulatory expectations versus needed incentives. Revenue adjustments should be sized so that companies will perform to standards rather than finding it economic simply to pay penalties. In addition, Staff must have access to all underlying performance data for auditing purposes. Innovative performance plans should be developed through participation by all market providers. Utilities should have the ability to make incremental investments that represent modest calculated risks without fear of penalty, allowing the trial and error process that enables larger investments to be made with more confidence. While negative-only incentive approaches have generally produced acceptable results, in order to achieve more enhanced performance it may be necessary to consider symmetrical incentive approaches that would reward the utility with additional earnings if it achieves superior results in areas such as innovation and customer service. Utilities may have concerns regarding potential negative adjustments for metrics that depend on customer decisions, e.g., DER participation. One possible approach to address this would be through positive-only incentives, at least related to elements where direct customer participation is needed for the utility to achieve its goal. To address the "windfall" concern, in this scenario, initial rates could be set at a level in the low range of rate of return, with positive- only incentives for achieving higher levels of performance.
- *Adjust ROE given incentives from PIMs*: We don't understand how PIMs work if they are ultimately adjusted out of the ROE. We generally agree with mechanisms that counter the utility's current incentives to increase rate base.

2. Please provide any recommendation regarding the metrics outlined in Tables 4, 5 and 6 to ensure they are comprehensive and specific. In particular, please provide any recommendations related to development of the metric formulas.

   Reply:

   - Table 4:
     - Isn't system security and reliability ultimately a system efficiency issue (if existing ISR and SRP programs aren't ensuring future system security/reliability, as per Energy Plan, do we need a new performance metric?)?
     - Should there be express marker for induced price effect of demand reduction?
     - Is there a way to better incentivize innovation?
     - System performance (voltage stability/equalization, operational flexibility, fault current avoidance)?
     - Systemic impacts of low-income reforms (eg, reduced consumption reduces bill and collection costs)?
     - Formulas aren't clear as stated – unclear how they track performance in specific direction. For example, should first read "reducing RI's monthly contribution to the ISO coincident peak?"
     - Don't understand "by sectors" in formula for distribution peak demand – how is performance traced through sectors (separate incentive for every sector)?
     - Should formula for DG friendly substations, factor in costs (extent) of required upgrades?
     - Does formula for time varying rates effectively address other load factor metrics?
     - Why don't formulas for distributed generation, storage and EVs include calculation of net value (benefits vs costs) per Docket 4600?
     - We strongly agree with the last metric. Failing to effectively mitigate carbon risk will lead to higher shareholder and lender risks, as well as unreasonably burdening ratepayers with higher costs.
   - Table 5:
     - In formulas, all value should be assessed according to valuation criteria established and approved in Docket 4600, for distribution system, customers and society.
     - Why don't formulas for distributed generation, storage and EVs include calculation of net value (benefits vs costs) per Docket 4600?
     - What are the performance benchmarks (unclear as stated)?
   - Table 6:
     - Advanced metering formula should include cost/benefit
     - Formula for Interconnection Support should include criteria on cost of interconnection (benchmark to bring cost down). Not clear that difference between study cost estimate and final cost is best means to control cost. Could be a feasibility metric as well – eg, capacity to interconnect (which ties back in to system planning).
     - On 3rd party access to distribution information, it should be about capacity for stakeholder participation in planning for future system capacity as much as transparency of current constraints. As set out

in our initial comments, in California, AB 327 requires IOUs to file DRPs that include scenario-based planning as well as integration analyses. Scenario-based planning accounts for different DER adoption scenarios, as well as other factors that might impact the need for DERs, such as retirement of large power plants. The CA IOUs are required to define the criteria for determining what constitutes an optimal location for DER deployment, and then identify values for the deployment via online mapping tools. The IOUs are also required to conduct integration analyses to measure the threshold integration of DERs, based on assumptions related to DER impacts on electric system reliability and safety.

- Same for distribution system planning – benchmark should reward utility for stakeholder participation in and proactive utility capacity enhancements. We need comprehensive and transparent thinking on system capacity to meet goals set by State.

3. If there is an area that would benefit from a metric not included here please provide any recommendations for it.

   Reply: See above.

4. Among the three broad groups of metrics, System Efficiency, Distributed Energy Resources and Network Support Services, please provide recommendation of how much weight should be allocated to each broad category, perhaps in terms of percentage of a total performance incentive allocation budget.

   Reply: This seems to be a question of putting a relative value to system, customer and society on each performance area. We would advocate a Docket 4600 valuation analysis as the reasoned foundation for these percentages. Without such an analysis, I'd submit that they're each integrally related (for example, why is interconnection support a network support service rather than a system efficiency performance area?) and assign each 33%.

5. Please provide any recommendations for how you think the metrics should be structured, or nested, within the broad categories.

   Reply: No comment.

6. Please provide any recommendations related to any of the Innovation Partner Models described on page 11 of this document.

   Reply:

   - Why not include community-based programs including microgrids (per the recent OER study on the subject)? Other business models include community aggregation programs (e.g., municipal, community, commercial, non-profit), community and multi-family building based renewal energy projects, regional "Main Street" venues which might include the sponsorship of micro grid projects or community based DER/generation projects, and "buy local" green power initiatives. New technologies are being developed by a wide array of companies, some very large and well-established, others start-up, that will invariably lead to additional innovative products and services if markets are established that enable customers to have access to these products.

- Implementation of thermal energy solutions on a scaled/shared basis? Arlington County, Virginia, and St. Paul, Minnesota, are both recognized as champion cities in the U.S. for their district-energy cooling and/or heating systems. A recent United Nations Environment Program (UNEP) district energy report notes that one of the most cost-effective means for reducing greenhouse gas emissions and primary energy demand is a modern district-energy system, especially one that incorporates combined heat and power (CHP, or co-generation). The analysis finds that modernizing district-energy systems can reduce heating and cooling primary-energy consumption by up to 50%. Since many systems are developed and/or operated by private-sector companies for communities, this opportunity also represents a unique public/private partnership. Co-benefits include cost savings from avoided and/or deferred investment in power- generation infrastructure, peak-load reduction, local investment and tax revenue, and local employment.
- Providing for integration of competition for greater efficiency and value where regulatory controls over monopoly aren't working?
- How about creating a distributed system platform? In NY, the REV proceeding seeks to create a distributed system platform that allows customers, third-party service providers, and energy service aggregators to interact, not unlike other platform markets such as computer operating systems and smartphones. For example, the Apple iOS and iPhone serve as the platform on which other services are available, linking data and algorithms to devices that perform countless tasks, such as car sharing.
- "Infrastructure as a service model" proposed by Solar City (see our initial comments)?

Additional comments on "Initial Considerations on Utility Compensation

1. General comment: Given the conclusions reached in this report, National Grid can no longer be left in a position to administer energy programs and decisions, without significant oversight, until the utility business model has changed. The conclusions we reference include (but are not limited to):

- Page 1: "First, today's utility compensation framework creates a bias for one-way, capital intensive solutions to fix identified constraints in the distribution system."

- Page 2: "this [utility compensation] framework creates several financial incentives that tend to encourage deployment of capital intensive solutions, as opposed to distributed energy resources, and may inhibit development of a long-term technology strategy."

- Page 6: "If the financial rewards available from PIMs are large enough, they can replace the revenues that would otherwise be provided to the utility from its return on rate base. Reducing the allowed return on equity can therefore reduce a utility's incentive to increase its rate base.

We recently attended an Energy Efficiency Resource Management Council meeting in which National Grid reported to the Council that it was unable to find any economical non-wires alternatives as part of its evaluation of system reliability procurement. It was no surprise they could not find such alternatives given their current incentives.

National Grid continues to assess a tax on interconnection of renewable energy projects long after the IRS established a safe-harbor exempting such generators from that tax even after Wind Energy Development (WED) petitioned the PUC to prohibit that tax in January 2014 and after IRS clarified its guidance to (once again) expressly safe-harbor renewables against the tax in June 2016. It is no surprise National Grid assesses an unjustified tax on renewable energy generators given its incentives.

In December 2014, after WED petitioned the PUC on the interconnection tax and other interconnection matters (like estimating interconnection costs without any true up), National Grid assessed Wind Energy Development an estimated interconnection cost of $12.7 million for seven proposed wind turbines in Coventry, rejecting three as infeasible. The utility only approved interconnection of all ten turbines at a total cost of $4.1 million after WED invested substantial resources in another PUC petition. It was no surprise that National Grid attempted to obstruct interconnection of that large project, given its incentives.

We have long advocated for National Grid's implementation of the locational incentive first called for as part of the statute enacting the Renewable Energy Growth program back in 2014, but the utility has yet to implement that incentive for projects located in such a way as to reduce burden on the distribution system. That is no surprise given National Grid's incentives.

We attempted to intervene on National Grid's Infrastructure Safety & Reliability planning process back in 2016 in part based on a contention that, "Despite crushing increases in energy prices caused by over-reliance on transmission constrained natural gas and our State Energy Plan's call for diversification of our energy supply in order to enhance security, reliability and affordability, this proposed plan says nothing about planning or implementing capacity upgrades to facilitate the integration of renewable energy." The Division opposed our motion to intervene and the PUC denied it, but ultimately the PUC concluded that "National Grid has admitted that, partially due to the nature of the distributed generation application process, there is little integration of the distributed generation program into the overall planning process. . . Testimony in this docket supported the ability of long-range studies to take system reliability, energy efficiency and distributed generation considerations into account. The long-range studies need to include consideration of distributed generation on the distribution system." Final Order, Docket 4539, pp. 20, 26 (Oct. 21, 2015). Here again, it was no surprise that, given their current incentives, National Grid's ISR planning process gave insufficient due to the opportunities distributed energy resources provide.

Our advocacy on streetlight reform determined that the utility's tariff refused to allow municipalities to access the (long obvious) financial value and other rewards that flow from conversion to LED lighting. That too was no surprise given the utility's incentive.

Our Lieutenant Governor's comments on the proposed guidance for implementation of Docket 4600, designed to achieve better value across our energy policies and decisions, is that the methodology developed unanimously by stakeholders and an experienced consultant is so complicated that only National Grid can understand it and left without ratepayer comprehension and scrutiny can only expect it to be administered to benefit the utility and harm Rhode Island customers (see attached). We submit that there is no question that the pursuit of long-term value is a complex proposition and that it is inherently challenging to implement best value decision-making without the kind of detailed analysis that RI's energy stakeholders called for in Docket 4600. We submit that the (legitimate) concern lies not in the complexity of the required analysis, but in the entity that manages and implements it. If the Docket 4600 analysis is conducted by a neutral party without a financial motive, it can be used to raise the level of understanding for all of us so that together we all can participate in providing better value for our energy system.

It is hard to blame National Grid for this behavior; it is no secret that they are a for profit enterprise driven principally by the goal of generating revenue to their shareholders. A monopoly utility will only place customer or societal interests above its own profit motive when it is carefully and thoroughly regulated to do so. The most alarming element of this history is the reality that most private and public sector investors seeking to invest their own dollars to bring valuable benefits to our electric system do not have the resources to overcome these obstructions, especially given the utility's deep ratepayer-funded litigation and lobbying budgets. It's hard to know how many valuable projects have become infeasible because of administrative obstruction. All of this points clearly to the reality that National Grid cannot be relied on to administer energy decisions, policies or programs unless and until we have changed the utility compensation model to ensure that National Grid's interests are entirely aligned with those of its customers and of Rhode Island.

2. Context: The Current Utility Business Model

- It will help stakeholders and the general public to have more context, so we can fully understand the framework in which we're working. For example:
    - In the first sentence explain "a compensation framework of cost-of-service ratemaking with a one-year forward test year and revenue decoupling." Where does that come from, why and how does it work & what are its implications? Does decoupling policy include presumed entitlement to return on investment

at set and inevitably increasing rates? If utility compensation and return on investment is itself a large part of our energy budget, is there a means to reduce that compensation if we successfully reduce their administrative costs and functions (i.e., become more self-reliant)?

- On page 3: how does RI peak relate to regional peak? For example, do RIers pay for electricity based on RI peak or regional? If regional, do these efforts to reduce peaks rely on commensurate efforts across the region to realize value? How does that work & does that system need improvement too? Who should be engaged in federal, regional reforms that will enable RI to attain the better long-term value (reduced costs and enhanced benefits) it will deserve for these efforts?

- On page 4: if the PIMs in the chart are a result of statutes, can they be changed for a more comprehensive, consistent and better-conceived approach to performance incentives? Why would the utility need to be paid to fulfill functions that benefit its customers? Isn't that its intended and regulated function? If regulation isn't working to provide value to the system, customers and society, why not reintroduce competition if/as possible? If those incentives are an element of expense to customers is there a way to sunset them (i.e., incentives to change monopoly's unregulated behavior become regulated expectations)? As the NY Rev, has reported – "Historically, most of our incentives have been one-way negative-only revenue adjustments. This approach was based upon the premise that the utility has an obligation to serve and is given the opportunity to fully recover its costs and earn a fair return on investment. Under this approach a positive incentive is arguably an unnecessary windfall, and negative revenue adjustments are necessary to enforce the obligation to serve. A result of this approach, however, is that the only way for a utility to enhance its earnings is to cut spending, and no explicit rewards are provided for providing superior service or otherwise meeting policy objectives. Ratemaking should optimize the level of inputs needed to achieve policy outcomes; near-term reduction of expenses will not always achieve this goal."

- On page 5: Last sentence before "Multi-Year Rate Plan" section is very hard to understand. It reads "existing regulatory tools provide significant potential to reform the incentive structure of the distribution utility." Does that mean existing incentives are poorly conceived and could easily be improved?

- **Typos:**

- Page 4 – an extra, hanging parenthetical.
- Page 5 – in first paragraph, dash should be a comma; under rate case moratorium, “with” should be “will”