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 Initial Considerations on Utility Compensation
National Grid's Comments

Dear Members:

On behalf of National Grid,[1] I enclose the Company's comments in response to the initial considerations and additional questions outlined in the Division of Public Utilities and Carriers and the Office of Energy Resources request dated August 15, 2017 to inform the ongoing inquiry into distribution system planning.

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
Initial Considerations on Utility Compensation

National Grid's Comments in Response to the August 15, 2017 Initial Considerations on Utility Compensation

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National Grid appreciates the opportunity to respond to the stakeholder questions raised in the August 15, 2017 Initial Considerations on Utility Compensation (hereafter, "Initial Considerations"). The Company agrees that there is value in considering how achievement of Rhode Island's energy goals and vision for the electric system might be advanced by reforms to the utility compensation framework, and appreciates the thoughtful discussion in the document.

The Company offers some initial comments on the framing and context provided in the document, followed by answers to the specific questions posed by the Rhode Island Division of Public Utilities and Carriers (DPUC).

The Initial Considerations describe three key concerns with the current utility business model: 1) rate case frequency; 2) incentive to build rate base, and 3) reluctance to invest in innovative technologies. The Company notes that the characterization of the incentives created under the current regulatory framework is not consistent with the Company's actual history in the state. First, the discussion overlooks the regulatory obligation of the Company to have the infrastructure in place to serve customer-driven peak loads safely and reliably, the underlying economic and weather considerations that encourage customers to use electricity in the patterns observed, and 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, requiring the utility to demonstrate alignment with customer interests and regulatory standards.

However, the Company agrees that there is value in exploring how reforms to the current utility compensation framework can advance key policy objectives and deliver new benefits for customers. For example, as the Company noted in its earlier comments on the Notice of Inquiry into the Electric Utility Business Model and Request for Stakeholder Comments, the current regulatory framework creates 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. This is due to decades-long regulatory review that is risk averse with customer money. The Company's responses below to the questions posed in the Initial Considerations are intended to help inform the design of modifications to the existing regulatory framework to address those shortcomings.

Specific responses to the questions posed in the Initial Considerations are below.

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

The Company offers the following Comments on the multiyear rate plan ("MRP") elements outlined in the DPUC's Initial Considerations.

Rate case moratorium: As the Company noted in its earlier comments, given the inherent complexity involved in transitioning to a multi-year rate plan, a shorter period (e.g., 3 years) is likely most appropriate initially. That said, the Company looks forward to discussing with the DPUC and other stakeholders how the length of the multi-year rate plan might evolve over time as processes, methodologies, and design are developed and refined. For the immediate term, the Company also believes that a shorter moratorium is more appropriate amidst ongoing efforts on grid modernization, in order to ensure that utility and regulatory priorities remain aligned, and to allow for adjustments in priorities if needed. However, the Company is open to discussing and supporting a transition to a framework that would justify a longer moratorium.

Attrition relief mechanism: The Company suggests that in the immediate term, adjustments in revenue over the rate period be based on Company forecasts. Particularly for shorter time horizons, Company forecasts are likely to be more accurate than revenue adjustments based purely on an index. However, the Company is open to evaluating the appropriateness of potential index-based mechanisms as discussions on multi-year rate plans advance.

Cost trackers: The Company agrees that cost trackers are an important tool for recovery of certain types of costs for which the utility has no or limited control, as well as the costs of utility-implemented programs required by state law.

Earnings sharing mechanism: The Company believes that an earnings sharing mechanism can be an appropriate tool for mitigating risk to both the Company and customers, and discusses this concept further below.

***Performance Incentive Mechanisms (PIMs) to prevent degradation of service*:** Given the existing performance incentives around service quality, the Company suggests that additional metrics and incentives are not needed in this area.

***PIMS to achieve specific goals and shift utility incentives*:** National Grid believes that carefully designed performance incentives can help to support the efficient delivery of state policy goals and provide broad new benefits to customers. The Company supports the development of performance incentive mechanisms in support of the key outcomes discussed in the questions that follow.

Adjust allowed ROE considering potential revenues from PIMS: The DPUC's proposal suggests that if the potential financial rewards from PIMs are large enough the Company's allowed ROE could be reduced, thereby reducing any incentive to increase the rate base. As the Company noted in its earlier comments, regulatory scrutiny of capital investments helps to ensure that any capital investments by the Company provide a clear benefit to the system and, ultimately, customers.

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, 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.

The Company suggests that 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, the Company suggests that 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 returned to customers.

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 the development of the metric formulas.

National Grid supports the development of PIMs in the three categories identified by the DPUC. The Company suggests that the greatest benefits to customers will come from designing metrics and incentives to conform with the following principles.

- Performance incentives (and the metrics that support them) should link directly to clearly articulated policy goals and outcomes that provide clear value for customers.

- Metrics included in performance incentives should be streamlined where possible in order to avoid redundancy and promote the most efficient use of Company and customer resources to achieve policy objectives. In developing PIMS, the Company recommends that the DPUC focus initially on a core set of 4-5 metrics. This will enable each metric to have a sufficiently meaningful incentive that will enable the Company to focus and prioritize resources in order to achieve targets and deliver customer benefits.

- Policy goals and selected metrics must be carefully defined and harmonized in order to prevent conflicting incentives and outcomes. For example, care must be taken to avoid circumstances where the goals of increasing distributed energy resource (DER) penetration and reducing customer costs and bills run counter to each other. Metrics and incentives could similarly run at cross purposes. For example, an incentive focused purely on demand response kW savings could encourage calling of these resources when they are not needed for the system. Harmonization is important in order to drive the most cost-effective and beneficial outcomes for customers in the aggregate.

- Metrics supporting performance incentives should be based on outcomes with a history of measurement or an otherwise clear ability to measure with minimal controversy.

- For metrics that regulators deem important enough to warrant an incentive, but for which there is limited measurement experience or capability, development of targets and incentives should be delayed until sufficient measurement capability has been established.

- Where possible, targets for performance incentives should be determined such that the customer benefits associated with achieving the target exceed the costs of doing so.

The Company offers the following comments and recommendations on specific metrics being considered by the DPUC.

System Efficiency Metrics

Transmission Peak Demand and Distribution Peak Demand: The Company believes that a single peak demand metric is likely to be more efficient than separate transmission and distribution peak demand metrics. After adjusting for losses, the transmission and peak demands are essentially the same number, so separate metrics around both are not needed. Therefore the Company proposes one System Peak Demand metric that would address both monthly ISO-coincident peaks and the annual ISO coincident peak. The metric would focus on peak reductions in the summer peak season, as a monthly summer peak is likely to coincide with the annual system peak. Reductions in the Company's peak demand during these months can provide savings over what customers would have paid by lowering the Company's monthly contribution to system-wide transmission costs, as well as by lowering the state's contribution to the costs of the forward capacity market (FCM) relative to what it would have been. Distribution cost reductions are possible to the extent that peak reductions lead to the deferral of new capacity investments.

Substation Peak Demand: A substation peak demand metric is potentially of value to customers if it encourages load factor improvements at highly- loaded substations that result in possible future deferral of upgrades. This metric should contribute to the System Peak Demand Metric defined above, and focus on the ISO-coincident peaks of the identified substations. As the Company's heat map concept is fully realized, it could show these heavily loaded substation transformers. We would note that assessment of this metric is only possible at substations with interval energy information, which is currently about half of the substations in RI.

DG-Friendly Substations: The Company would support inclusion of a metric for performance incentives that measures the number of substations that have been either retro-fitted or initially installed with high side ground fault protection (also known as a 3V0 upgrade). This allows for the installation of as many kWs of DG up to the thermal rating of a particular substation transformer.

Distribution load factor: The Company does not believe that there is value in including distribution load factor as a metric for a performance incentive. Analysis conducted by the Brattle Group on behalf of the Joint Utilities of New York[1]concluded that utility efforts to improve system load factor – which would largely focus on reducing peak demand and increasing off-peak sales, are unlikely to have a meaningful and distinct (i.e., distinguishable from the expected level of statistical variation) impact on system load factor. The Company suggests that DPUC focus instead on developing performance metrics that would reward efforts that are directionally aligned with load factor improvements, such as peak reduction and increasing beneficial off-peak load.

Customer load factor: The Company would advise against inclusion of a performance incentive targeting improvements in customer load factor. Measurement of load factor by customer class requires interval metering, which has not been deployed across small commercial/industrial and residential customer classes. Further, efforts to target improvements in load factor by customer class are likely to be the same efforts relied upon to achieve either system coincident peak reductions or reductions in substation peaks. Therefore, they are likely to be captured by the peak reduction metrics above.

Time-varying rates: The Company believes that a metric measuring the penetration of time-varying energy rates could be a useful metric for a performance incentive mechanism at a later date, upon implementation of advanced metering functionality.

CO_2 intensity: The Company is generally supportive of the concept of an incentive around carbon intensity, but notes that key actions that the Company might take to reduce carbon intensity (demand response, integration of distributed generation, and energy efficiency) are already captured by other metrics being considered. An alternative might be a performance incentive mechanism for CO_2 reductions driven by utility efforts to expand beneficial electrification.

[1] Zarakas et al. 2017. Assessment of Load Factor as a System Efficiency Earning Adjustment Mechanism. Prepared for the Joint Utilities of New York. February 10.

Distributed Energy Resources Metrics
The Company notes that it currently reports or has the ability to report all of the metrics in Table 5. The Company suggests that any new metrics around DERs be as streamlined as possible and focus on key outcomes. For example, performance incentives mechanisms focused both on percent of customers with a given resource and installed capacity of a given resource are unlikely to promote the most efficient use of Company resources. The Company suggests that performance incentives for DERs also capture and reward contributions from the beneficial electrification of heat. Specific comments on the metrics included in Table 5 follow.

Energy Efficiency: The Company already reports on participation and $/MWh. The Company does not believe specific performance targets or incentives around participation and $/MWh would be beneficial. In regards to participation, there are certain programs like upstream programs, lighting, and products, where the Company cannot track participation in order to reach all customers in quick and effective ways. The Company has already demonstrated commitment to improved reporting on unique participants in the Year End Reports. The Company also commissioned a participation study that will help target new customers. Rhode Island is a leader in the US when it comes to our reporting on unique participants and we will continue to report and strive to reach more customers. But as we transform the market by moving more programs to upstream, it will become increasingly difficult to track unique participants.

Regarding the $/MWh metric, there are already existing requirements in place that address this metric. Least Cost Procurement requires the Energy Efficiency plan to be cost effective and cost less than supply. In addition, the dollar amount per unit of saved energy is trending upward year-over-year due to significant saturation of relatively low cost energy efficiency measures, federal standards and baselines, and the application of evaluation results.

The Company is open to working with the EE settling parties including the DPUC and Energy Efficiency Resource Management Council on possible new metrics in annual plans. As alluded to in National Grid's first draft of the 2018-2020 Energy Efficiency Plan, any new metrics would not be until program year 2019.

Demand Response: The Company believes that activities around demand response are generally best addressed through the system or substation peak demand metrics. A specific demand response capacity savings target could effectively create an incentive that encourages the Company to call DR events in order to achieve the savings, even if such events do not provide benefits to the system of customers (e.g., during a cooler-than-average summer). Metrics around kW enrolled or the percent of customers enrolled could be appropriately included in the customer engagement metrics discussed in the next section.

Distributed Generation: The Company advises against setting specific targets and performance incentives for individual distributed generation technologies, since doing so is unlikely to lead to the most efficient outcomes for customers. Instead, the DPUC might consider a broader metric and target that captures all new incremental installed DER capacity or estimated output. The Company would suggest that such a metric incorporate energy storage. Alternatively, a metric might be developed to advance programs of importance to the state for which the Company does not currently receive an incentive, such as virtual net metering.

Electricity Storage: The Company suggests that a specific performance incentive for electricity storage is not warranted at this time, but that storage could be incorporated into a broader DER metric.

Electric vehicles: The Company believes that there is value in supporting beneficial electrification of both transportation and heat with performance incentive mechanisms, and suggests that the most appropriate metric(s) will be dependent on Company offerings. However, the Company suggests that the percent of customers with EVs enrolled in demand response programs may not be a viable metric in the near term, given that such participation – if it involves cycling of energy from vehicle to grid – currently violates the terms of most automotive battery warranties. Participation in off-peak charging programs may be a more appropriate metric.

Network Support Services Metrics

Advanced metering capabilities: The Company is supportive of a potential incentive around deployment of advanced metering functionality. The appropriate structure of such a metric will be best determined within any proceeding designed to further advanced metering in the state.

Interconnection Support: Recently signed legislation has established new requirements around construction of customer-funded upgrades. As part of that legislation, the Public Utilities Commission (PUC) is expected to open a docket shortly to establish metrics for the Company's performance in meeting these requirements, and may consider penalties and incentives in those metrics. In addition, in the 2017 RE Growth proceeding (Docket No. 4672), the PUC directed the Company to propose performance metrics associated with the interconnection process as part of its 2018 Program Plan. The Company suggests that any new metrics be considered holistically in the context of these proceedings. With respect to the interconnection metrics listed in Table 6, the Company would note that a metric around average days for interconnection, if intended to be used for a performance incentive, should take into account the size of projects.

Customer Access to Customer Information; Third Party Access to Customer Information: Additional detail is needed in order to evaluate these metrics. It is not clear from the draft proposal the nature of the data being considered in the metric. For Customer Access to Customer Information, the ability of customers to access hourly usage data would be dependent on AMF. With respect to Third Party Access to Customer Information, all customers currently have the ability to make their data available to third parties. It is not clear from the proposal if this metric is intended to require the Company to make additional data available to customers or if the metric is intended to capture data that would be available after AMF deployment. Customer privacy must remain an important consideration as the DPUC considers potential metrics.

Third party Access to Distribution Information: The Company plans to address this metric through the Heat Map and RI System Data Portal it plans to develop, and would suggest a potential incentive be tied to achievement of timelines for the progression of the information available.

Distribution System Planning: The Company would suggest that this metric be a subset of the prior bullet (third party access to distribution planning) showing the progress of the development of the proposed RI System Data Portal showing current and past ISR filings, other PUC-related proceedings, heavily and lightly loaded parts of the distribution system, and future possible RFPs for non-wires alternatives, would be appropriate as the beginning of a Distribution System Planning metric and performance incentive. While the DPUC's proposal suggests incorporation of accuracy of heat maps into a metric, additional thought and deliberation would be required to consider how accuracy might objectively be assessed.

Customer Engagement: The promotion of customer engagement is a common theme in the State's energy policy goals, and the Company believes that performance incentive mechanism(s) in this area can help to provide new opportunities for customers to engage with both the Company and third-parties. Possible metrics could include a customer engagement survey, which measures survey scores from customers who make purchases on specific platforms that also promote third-party vendors, a transactional conversion rate that measures the frequency at which unique customer visits on specific platforms results in a purchase, or participation in innovative Company programs.

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

In addressing question 2, the Company suggested incorporation of beneficial electrification of heat into any eventual performance incentives around either DERs or CO_2 emissions.

In addition to the metrics above, the Company is also receptive to discussing new performance incentive mechanisms around improved outcomes for income-eligible customers, cybersecurity, and, while outside the scope of the Power Sector Transformation Initiative, other natural gas-related issues such as the Company's new gas business enablement program or expanding an AMF deployment to include gas meters.

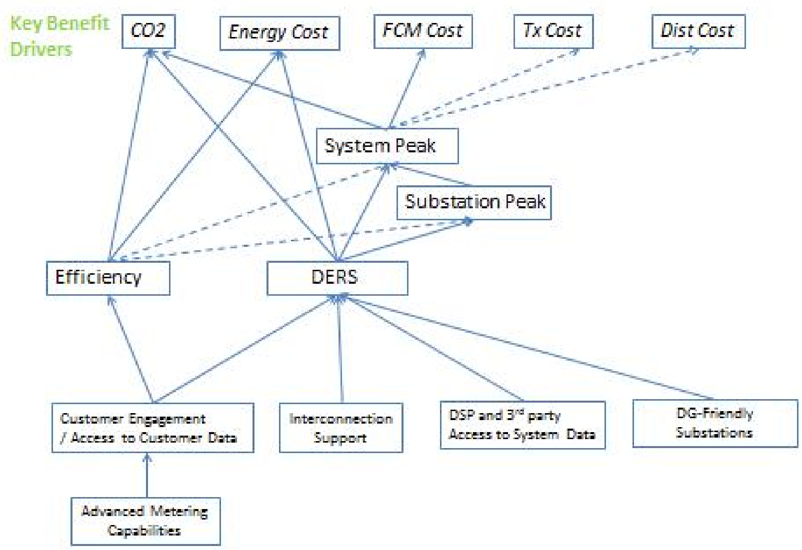
4) Among the three broad groups of metrics, System Efficiency, Distributed Energy Resources and Network Support Services, please provide recommendation of how much weight should be allocated to each broad category, perhaps in terms of a percentage of a total performance incentive allocation budget.

As a general rule, the Company suggests that performance incentive categories, and ultimately the metrics within each of them, be weighted in proportion to the net benefits they are expected to deliver to customers. Where benefits cannot be quantified, the importance of the category or metric to delivering key policy goals and potential customer benefits should be considered. Absent a final set of metrics and evaluation of the targets that will drive these benefits, it is premature to suggest a specific weighting for the three categories.

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

Figure 1 below provides a diagram that represents how potential performance metrics and their underlying activities directly and indirectly impact key benefits drivers. The Company believes it is valuable to visualize the interaction between metrics across the three categories.

Figure 1
Overview of Relationships between Potential Performance Metrics and Key Benefit Drivers



Note: Solid arrows suggest clear and direct relationship; dashed arrows suggest relationship that could apply under certain conditions. For the purposes of this figure, DERs include Demand response, distributed generation, and beneficial electrification.

As Figure 1 suggests, reductions in system peak contribute directly to benefits in CO_2 reductions as well as reductions in FCM costs from what would otherwise occur, and are likely to support reductions in transmission and distribution costs relative to what would otherwise occur. Reductions in ISO-coincident peaks at the most heavily-loaded substations would contribute to the overall peak reduction target, and an independent target would be established for this metric. Incremental DERS and Energy Efficiency would be expected to support system peak reductions directly as well as through reductions in peaks at identified substations. However, the Company would advise against specific peak reduction targets for either DERs or Energy Efficiency in order to avoid encouraging the use of specific resources to meet peak reduction targets. DERs and Energy Efficiency also contribute directly to CO_2 reductions and Energy Cost reductions. Activities in support of metrics in the Network Support Services category help to support achievement of targets for DERs and Energy Efficiency. Although a specific metric has yet to be defined, the Company anticipates that any metric will capture efforts to encourage customer adoption of DERs and Energy Efficiency measures. Greater availability of customer data to both the customer and third-parties will support Company and third party efforts to advance adoption of these resources. Efforts to improve the interconnection process will support distributed generation installation, as would efforts to increase DG-Friendly Substations (listed under System Efficiency). New initiatives around Distribution System Planning and availability of system data will support DER integration. Finally, AMF deployment would greatly enhance data availability, and provide new opportunities to use customer data to drive DER adoption and efficiency investments.

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

The Company agrees with DPUC 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 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 DPUC represent greater partner involvement than might occur under a traditional vendor-customer relationship, in that the partner to the utility might be expected to contributed capital or take on some level of risk, with the goal of ultimately providing new services and opportunities to customers at a lower cost to them 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 a first step, the Company suggests that DPUC 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 large enough to capture utility executive attention, and should be commensurate with the level of risk borne by shareholders.

- Specific system needs may 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, state/federal law and/or requirements, as well as utility standards of conduct.

- At this point, it is premature to consider potential earnings through the activities described below as substitutes for utility for cost-recovery under traditional cost-of-service ratemaking. The potential size of such earnings, and their ability to support utility cost recovery, remains untested. The utility's monopoly position, as well as standards of conduct established under restructuring may limit the utility's ability to pursue potential new earnings opportunities.

The Company provides some additional comments on the specific partnership models considered by DPUC below.

1. **Utilization of shared communications infrastructure.**
   The Company is working to explore and evaluate potential partnership models around shared communications infrastructure and the ability to define these models in a manner that is consistent with the suggested principles above. The Company notes that any potential restrictions or impacts under applicable federal and state law on the ability of a Rhode Island public utility to undertake or participate in the proposed shared communications infrastructure arrangements would need to be identified and assessed before the Company would be in a position to commit to any particular partnership model.

   The Company must provide for a safe, secure and reliable energy delivery system. Any considerations for shared networks must ensure this minimum service expectation can be met. This includes meeting network availability and service level expectations, quality of service for protocols and communications options, assuring data latency is minimized, ability to scale or grow the network, supporting real-time data transfer, cybersecurity protocols and standards. The investment, maintenance and support of any shared network must also be considered. As suggested above, there will be mission critical aspects of distribution utility operations where it may not be prudent to use a shared network if cyber security issues cannot be addressed. Hybrid approaches, e.g., utility ownership for elements of the network that are mission-critical or present cyber security risks, with potential partnerships for other elements, may provide a potential solution to this challenge.

The Company notes that it currently has a partnership agreement for a shared network with Verizon. Verizon's wireless service and landline offerings provide a significant amount of meter reading and operational data for the Company.

Finally, the Company notes that partnership agreements will take time to develop and materialize, such that interim solutions may be needed to advance communications priorities. More complex models involving numerous partners would be expected to take longer to enact.

2. **Advanced meters.**
In its response to the May 1, 2017 Notice of Inquiry into the Electric Utility Business Model and Request for Stakeholder Comment, the Company outlined its arguments around the economic benefits of utility ownership and operation of meters. In addition to those arguments, the Company notes that the economies of scope discussed in that response become of increasing importance in the context of AMF. The implications of AMF deployment are far more expansive than replacement of AMR for meter-to-cash purposes, in that AMF is an information and communications "system" that is integrated into the overall operation of the utility from Operations to Customer Service, as well as Billing, and therefore is best managed by the utility. Utility ownership and operation of meters is an essential component of successful, cost-effective AMF deployment.

AMF, coupled with data management systems and customer engagement portals, will provide a platform to enable an array of future utility and third-party offerings. In addition to collecting high-quality, granular usage data, meters allow communication between the utility and the consumer in a bi-directional manner, and serve as a common sensor on which the utility and third-parties could build new offerings. Underlying all of this new ability will be a robust security layer ensuring customers have a clear choice as to how and how much communication and data they exchange. As the Company indicated in its response to the May 1, 2017 Notice, the utility should not be precluded from participating (along with third parties) in the market to provide such services.

In general, the Company believes that customers will benefit the most from a competitive market environment in which multiple parties compete to provide new and innovative energy services. That said, regulators must consider how to most effectively protect customer interests in such an environment. The Company suggests that issuing licenses to operate such a platform to one or a small number of third parties could constrain the potential benefits to customers. Rather, the Company suggests that the National Grid might manage the platform in a way that enables participation of qualified third parties.

The Company currently relies on a third-party platform to provide interval data information to customers and customer-selected third-party energy suppliers who subscribe to this service. Providing a similar type of platform for the broader set of customers would be a logical next step once interval usage data is available, and the development and management of this platform is a natural role for the Company to play given its experience in connecting customers with program opportunities and qualified third-party providers. For example, the Company's existing energy efficiency and demand response programs are already designed to enable multiple providers – from EE programs offering incentives for any qualifying devices to DR programs allowing customers to "Bring Your Own Thermostat." New and enhanced programs would follow the same design principles, such as open standards and recurring qualification processes, to ensure that customers have their choice of a range of qualifying technologies and vendors. New customer engagement portals established by the Company to leverage AMF could include an "e-commerce marketplace" wherein the Company could offer third-party energy efficient products and services directly to customers, and an expanded "connected device" portal that enables customers to enroll third-party qualifying devices in Company DR programs. Meter connectivity could also enable new types of related services by the utility and third-parties, such as monitoring of appliance or equipment health using energy consumption data (e.g. early warning of HVAC failure).

Utility operation of the platform, with regulatory oversight, is likely to be beneficial to customers at least in the early years of such a platform. Any platform should enable customers to securely share their data with other third party providers. Requirements around customer data privacy and security, as well as obligations for customer approval are currently managed by the utility. Under third-party platforms, the DPUC would need to consider how to address these issues. There would also need to be some market-based rules and standards developed, similar to the competitive supply rules, which enables market participation through a consistent and standard set of protocols to facilitate data exchange, security, and control amongst many third parties. If third parties offer fee-based services, there will also need to be market rules around how customers are billed and pay for those services.

3. **Electric vehicle charging stations.**
   The Company is committed to partnering with third parties to support the achievement of Rhode Island's transportation electrification goals. The Company agrees with DPUC that there may be opportunities to earn from non-volumetric services relevant to EV charging through the provision of new services to customers. As the Company noted in its response to the Notice of Inquiry and Request for Stakeholder Comment Regarding a Utility's Role in Deploying Beneficial Electrification with a Focus on Plug-in Electric Vehicles, Rhode Island's aggressive goals for transportation electrification and greenhouse gas reductions may warrant an expanded utility role in EV charging investment and EV market development. Partnership efforts around EV charging that might provide opportunities for new revenue streams could include those listed, and revenue opportunities around market development, such as efforts to facilitate EV-related transactions, might also be considered. That said, further evaluation would be needed around the potential magnitude of revenue opportunities, and the Company would not expect such revenues to replace the revenue requirement associated with capital investment in EVSE and related infrastructure.

4. **Data analytics**
   While the Company believes that there is likely some earnings opportunity via provision of "information" as defined in the DPUC's Initial Considerations, the potential magnitude of this

revenue is unclear at this point. The willingness-to-pay of developers and other potential users for value-added system data has not been tested. It may be, for example, that willingness-to-pay for additional data is quite low until the level of specificity in the data reaches a level that may begin to encroach upon CEII and customer privacy concerns. Further, it is not clear how much of a market there might be for subscription-based services. A low number of subscribers is likely to imply a high-cost per subscriber, which could make potential offerings less attractive to DER developers. The Company suggests that at this point there is not a sufficient understanding of the demand for information services to infer the extent to which such revenues might offset other expenses.