nationalgrid

Rhode Island Division of Public Utilities and Carriers & Office of Energy Resources
Power Sector Transformation
Notice of Inquiry into the Electric Utility Business Model and Request for Stakeholder Comment

Responses of National Grid to May 1, 2017 stakeholder questions

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SECTION 1. WHAT FUNCTIONS SHOULD THE ELECTRIC UTILITY PERFORM?

One important step to establish the utility business model is to define the functions that the utility should undertake. The potential functions of a twenty-first century electric system may include:

- *Reliability services, such as pole and line maintenance, circuit reconfiguration, supplemental power supply, undergrounding, power factor correction, distribution system engineering and voltage variation optimization.*

- *Connectivity services including operation of the communications backbone to support distribution line automation and to enable potential advanced metering functionality.*

- *Network integration services, such as scheduling, multi-directional power flow and management services, storage-based power "loan" services, electric vehicle charging services, and the necessary distribution system planning and data analysis for load, voltage and hosting capacity.*

- *Transaction management services, such as aggregation, clearing and settlement among parties, integration of distributed energy resources with ISO-NE markets, metering customers.*

- *Customer engagement services, such as home energy optimization, appliance automation, intelligent load management, backup energy services including energy storage, energy efficiency program delivery, customer support, low-income engagement and electric vehicle education.*

Many of these functions are so connected with one another that they are best undertaken by a single enterprise. However, there may be functions that could be undertaken separately or which the electric utility may not be optimally organized to perform.

Questions for stakeholders on utility functions

1) Which of the functions described here are integral to the future electric utility?

National Grid's core and fundamental purpose is the safe, reliable, efficient delivery of energy to our customers. Many of the functions described above are integral to this core purpose, and while changes in the energy landscape may provide opportunities for new layers of service provided by the market, the core purpose of the utility (and therefore it's accountability to its customers) remains unchanged.

At the highest level two key themes can summarize the Company's core purpose and functions:

Theme 1: Ensuring reliability and safety

The safe delivery of energy is at the heart of the Company's commitment to customers and will continue to be at the core of everything we do. The ways in which we plan, develop and operate utility infrastructure are all conducted with reliability as a primary focus. Ensuring this safe, reliable delivery of energy manifests in a number of important ways:

- Ensuring public safety;
- Operating the network in real time, including circuit reconfiguration;
- Emergency and storm response;
- System design, planning, and engineering including new interconnections;
- Distribution line, substation, and underground maintenance;
- System protection (protection from an electric fault on the system); and
- Asset Management, including both asset health and inspections.

Theme 2: Responding to the broader needs of our customers

Trends towards decarbonization, decentralization, and digitization are driving a change in the way in which some customers choose to engage in their energy supply. In addition to the underlying requirement to efficiently deliver safe and reliable energy, more than ever our customers (small and large) are looking to the utility as a trusted partner as they seek visibility and control of their energy bills, new products and services, and an overall 'frictionless' service. The utility has a core role to play in meeting these broader customer needs; again this role manifests in a number of ways:

- System efficiency/optimizing network design and operations to manage long term system costs and deliver the right solution for customers;
- Reliable and robust metering services to ensure accurate and timely provision of usage information and enable customers to respond;
- Cost allocation and rate design to appropriately and equitably recover costs from customers in accordance with rate design principles;
- Seeking new ways to engage customers in their energy use and enable them to take action through providing information and choice (e.g., executing on our energy efficiency and demand response programs) and, looking ahead, considering the benefits for customers from moving to advanced metering; and
- Actively seeking out new energy solutions and working in partnership with third parties to deliver innovative solutions that create customer value.

The Company expects that the ways in which it delivers these functions may evolve. Strategic partnerships between the utility and third parties, in particular, can expand or enhance services provided to customers in a way that provides new benefits. The Company already works in partnership with many third parties to provide energy efficiency services and solar opportunities (energy efficiency audit firms, small commercial and industrial installers, solar identification, etc.). Expanding the number and types of partners will be a fundamental part of this strategy.

With respect to the specific functions as identified by the Division above, the Company believes that the following will remain integral to the utility going forward:

a) Reliability services, including the safe delivery of electricity is paramount. The utility model is uniquely structured and equipped to execute this role for the benefit of all customers. The Company anticipates this core function to remain integral.

b) Connectivity can be considered in multiple forms - connectivity to the electric grid itself provides the power necessary for our customers to produce their goods and services as well as enable the comforts of living in a modern society; grid connectivity provides the physical pathways for distributed energy resources (DER) to the marketplace services that enable enhanced visibility and operational oversight on

the distribution system; while telecommunications connectivity provides situational awareness and the ability to control and/or transact.

From a telecoms perspective, the Company has had connectivity services to major substations and many feeder breakers for decades to remotely 'see' the operation of equipment and be able to remotely operate critical devices (i.e., feeder breakers, voltage control equipment, etc.). More recently, the Company has sought to provide this level of operational transparency farther down into the system on to local distribution feeders. The Company expects that these 'critical' needs are best met when the utility is assured access, control, and securely to the telecom networks; to that end, we anticipate accountability for critical connectivity needs to remain integral to the utility.

c) Key network integration services, in particular distribution system planning and analysis, will remain central utility functions. The utility's performance of these services is essential to meeting our obligations to customers, particularly as the volume of DER on the system increases. The utility is uniquely advantaged to identify where DER can be added to the system in a way that benefits customers, or to identify where on the system such integration faces constraints. However, there are opportunities to explore partnerships with third parties to provide certain network services, such as interconnection of new distributed generation customers and electric vehicle (EV) charging.

d) Key transaction management services, in particular metering, load settlement for the competitive energy markets, and generator settlement to provide an offset to above-market costs for renewable programs, remain important utility functions. The Company has a long history in these roles as an 'honest broker' for a well-functioning infrastructure characterized by accurate measurement. The ISO-NE requires an 'independent' meter reader for these services that can't be associated with any company that, either through direct or indirect action, benefits from ISO-NE market activity. The Company has served that role in an accurate and timely manner for decades.

As metering infrastructure continues to advance, supporting two-way power flow and providing customers with information and choice, there is an ongoing role for the utility as a trusted party with the skills and capability to own and operate this important infrastructure. The value provided by the Company in this area is particularly important as the transition to advanced metering functionality (AMF) is considered. Full deployment of AMF is likely to be subject to significant economies of scale and scope, such that utility deployment would be expected to provide savings to customers relative to deployment via competitive markets. The need for meters to fully function on the Company's platform and communicate effectively and securely with the Company's information systems is one source of these expected savings. Further, the Company's interests are inherently aligned with customers' interests in ensuring that the potential system benefits of AMF are achieved at an acceptable cost and over an acceptable timeframe. This is less likely to be the case for competitive meter providers, for whom financing is likely contingent on higher returns than regulated utilities can earn. In addition, given the regulatory oversight necessary to ensure accurate metering, continued utility ownership and operation of meters is likely to result in lower regulatory costs than competitive metering. Finally, utility-owned metering avoids the costs to customers associated with the likely need to have new meters installed when switching between competitive providers.

Billing, on the other hand, has been effectively competitive since the transition to a competitive retail market for electric supply, though the Company commonly serves as the provider of billing services for nonregulated power producers.

e) As customer needs continue to evolve and new technology developments and falling costs bring a growing range of value-adding new assets, products, and services to market, the utility should not be excluded from participating in these new areas. From access to technologies such as storage (to be used a 'tool in the toolkit' in operating the grid), to the provision of home energy optimization services to lower customer bills and provide services to the grid, there can be value for customers in enabling appropriate utility participation.

   The role of the utility in supporting growth in EV is specifically worthy of note. While EV penetration to date is relatively low, achievement of state decarbonization goals will require significant growth in EVs in the coming 15 to 30 years. While a number of states have grappled with the question of how to stimulate EV growth, there is a growing consensus as to a multi-faceted role for utilities in building EV charging infrastructure, testing the network impacts, and importantly building on its role as a trusted advisor to customers, providing outreach and education.

   In the case of energy efficiency program delivery, the Company has over 30 years of experience implementing award-winning energy efficiency programs and looks forward to building upon this successful history through innovative approaches and new strategic partnerships with service providers to help customers manage their energy usage into the future.

   Notwithstanding the examples outlined here, the Company recognizes that customers can also benefit from access to a market for the provision of such products and services. In response to question 3 below, the Company notes specific examples where products, services, and functions might be provided via an unregulated third party or market solution.

2) Are there additional functions not described here that should be included as a strategic focus of the electric utility?

In the medium to long term, and building from today's starting point, the Company envisions performing the functions described above on a more modernized distribution system that is characterized by increased visibility through technologies such as distribution automation and AMF, and through both more sophisticated rate design and opportunities to utilize a variety of distributed resources, greater opportunity for active customer participation on the system.

In this environment, the utility, through its relationship with customers, will be positioned to provide a number of services to enhance the customer experience and optimize the system to the benefit of customers. These efforts are likely to include the utility providing a new suite of services related to connecting customers with third-party technology solution providers. It may also include partnering with third parties to provide new service and technology offerings to customers. Given the state's climate targets and interest in beneficial electrification, the Company's role may also include helping customers optimize their energy expenditures across end-uses. The Company will play a key role in ensuring that similar offerings and opportunities are made available to low- and moderate-income customers that might be overlooked by competitive market providers. Finally, the Company will, through carefully targeted incentives, play an important role in helping to deliver outcomes tied to key state energy policy goals.

It is also worth noting some specific actions that the Company believes can provide important benefits to customers in the near future.

- **Augmenting the work on climate change adaptation and resiliency**. The Company has been working for a number of years in this arena. Specifically, raising critical equipment above expected flood levels and installing larger diameter wooden poles to withstand future higher sustained winds and storm conditions.

- **Grid automation and digitization**. As discussed under question 1, continuing to modernize the grid through automation and digitization is a priority of the Company. Adding points of visibility to the system to enable real-time operational visibility and remote operation of critical devices will provide important benefits to customers in terms of resilience while supporting integration of customer-side resources and advanced metering technology.

- **Specifically managing ISO-NE coincident peaks**, both on a monthly basis to manage the transmission component of the delivery service provided by the Company, and to the annual coincident peak to manage the allocation of the costs of the capacity market that affects all customers' supply side costs.

3) Are there functions described here that should be provided by an unregulated third party, or through a market-based approach?

As described above, the Company believes that while there are a number of new functions and/or service layers that could be provided by an unregulated third party or the market, the utility should not be precluded from also participating in these areas. In short, while the following functions 'could' be delivered by unregulated third parties, it is not necessary that they 'should' be.

Examples of functions and service layers that fall into this category include:

Behind the meter infrastructure and services – already a competitive and growing segment, offering a range of new in-home products and services for customers seeking great comfort and control of their energy consumption and bills.

Engaging customers in their energy usage – similar to existing delivery models for energy efficiency, there is a clear role for third parties in this space. Competitive market participants have, and will continue to, develop a diverse array of technology solutions to help customers manage their energy use; the Company sees significant new potential here, as data and analytics (potentially provided by the utility) enable compelling customer propositions.

Broader opportunities arising from availability of customer data (used with customer permission) – the availability and utilization of customer data is an important element in developing new energy-related products and services (beyond energy efficiency) to provide innovative new customer solutions.

Connectivity solutions for non-mission-critical operations – in a modern, multi directional energy network there is an increasing need for communications. There is a clear opportunity for non-regulated third parties and/or the market to provide non-mission-critical communications services, for example, providing customer usage analysis or recommendations based on AMF data.

Peak reduction solutions – as tools such as the Company's recently developed 'heat maps' provide granular insights into the electric distribution system (highlighting areas where sustained higher loads could result in a need for infrastructure investment in the future), market driven requests for proposals (RFPs) could provide peak load reduction solutions, or potential opportunities for non-wires alternatives should they be warranted by load growth.

4) To the extent certain activities now being performed by the utility may be performed by other market actors, what type of oversight should be in place to protect customer interests?

The Company has a long history of managing customer relationships in a way that protects customer interests. Regulatory oversight of Company activities ensures this outcome. As the number and nature of third parties interacting with utility customers increases, it is essential that regulators and policymakers recognize that in order for the expansion of energy service markets to provide broad benefits to utility customers, it must be done in a way that ensures that customer interests are protected. Evidence of significant customer overcharging by energy service companies in New York, for example, has led the New York Public Service Commission enact new rules governing the activities of these companies. Efforts by the RI PUC and Division to promote customer understanding of market offerings and their bill impacts will be important.

5) Many of the functions described here require the utility to manage complex technology systems. What kind of regulatory approach could address the risk of technology obsolescence?

The Company and other utilities have and continue to manage complex technology systems dating back to the inception of integrated circuits, microprocessors, and larger computational platforms. Systems such as Customer Billing, Meter Data Management Systems, Energy Management Systems, Geographic Information Systems, and Maintenance Management Systems are just a few examples. The Company also manages a complex and ever-growing portfolio of equipment that has varying levels of both mechanical and technical complexity.

In fulfilling this function over many years, the Company has successfully demonstrated the ability to manage a portfolio of complex technology systems and equipment, while minimizing costs to customers and the risk of obsolescence. The Company has methodically and soundly assessed all major technology investments based on their support for the prevalent and emerging standards, protocols, and technical architectures.

In today's world, technological systems and solutions are not only purpose-built complex hybrid systems, but they often are multi-purpose platforms that enable a broad host of functions and services for varying applications and needs. The latest technologies in revenue metering, for example, are, essentially, hardware solutions employing modern computing platforms and operating systems. Moving forward, metering kWh for billing purposes may be a meter's (primary) function, however, applications running on the same device can allow it to be multi-purposed for SCADA / DMS / ADMS and Outage Management functions as well.

In this example, the same hardware is now used by different, isolated, systems for high-accuracy voltage monitoring and outage notification. The traditional concept of a metering asset quickly transforms into a complex component for supporting advanced grid management systems such as Volt/VAr optimization, and enhanced fault location, isolation, and service restoration (FLISR). From a utility perspective, this type of technology allows a single piece of equipment to serve separate roles for secure and isolated integration to

different back-office applications. From a customer perspective, this same technology can further enhance offerings through integration capability to home area networks and intelligent appliances within the premise. Aside from the various applications and services that such a hardware platform can support, it also becomes a node for extension of a complex, hybrid communication system. When considered from a comprehensive, holistic, technological solution perspective, it becomes clear that the risk of obsolescence quickly diminishes to margins well-managed through proper maintenance over the equipment's life (noting that well-managed and proper maintenance activities may be required more often than for more traditional asset classes for which the pace of technology change was much slower).

From a regulatory perspective, it is critical that the utility can invest to sustain complex solutions, to extend the life and occasionally introduce incremental value. Failure to maintain these investments is what ultimately creates an obsolescence risk, as the time and investment to catch-up (if possible) may be greater than the replacement cost. The Company has, in some areas, employed Software-as-a-Service (SaaS) approaches to deliver complex solutions and in doing so, de-risked the investment. While approaches such as SaaS result in different cost recovery (operating expense versus capital expense), the Company is committed to seeking out innovative/alternative such solutions that are in the best interests of customers.

Depreciation rates, as approved by the RI PUC, are another important tool used by the Company to effectively manage asset lives. Current depreciation rates for all new pertinent capital items are studied to determine if existing depreciation timeframes remain valid based on expected replacement dates. If a change is desired, it requires a proceeding at the RI PUC, which will likely require demonstrating that the cost impact of a change in depreciation rate for certain equipment will not increase customer bills too rapidly over time.

Overall, in spite of increasing pace of technology change and shorter technology lives, the Company is confident in its ability to develop and propose appropriate solutions, based on the outcomes the Division is seeking to achieve, that should not increase risk to customers or the Company.

SECTION 2. HOW SHOULD THE UTILITY BE COMPENSATED FOR EACH OF THE FUNCTIONS IT PERFORMS?

The electric utility currently sets its revenue requirement through cost of service regulation with some specific incentives. The utility recovers its revenue requirement from different rate classes of electricity end users based on cost causation principles. However, a number of the functions described here offer the opportunity for alternative revenue streams or the design of revenue collection based on cost allocation principles that seek to achieve different objectives beyond traditional cost-causation principles. For example, distribution system planning, data analytics, and connectivity all could support revenue from third parties (not end use customers) or could provide a basis for recovering the cost of those services in ways that are different than cost causation rate design might suggest today.

Questions for stakeholders on compensation

1) How should decisions made by a utility in performing particular functions affect the way it is compensated?

Compensation of the utility must occur in a way that supports a utility's ability to fulfill its obligation to customers in an affordable manner. The utility is responsible for the safe, reliable, and efficient delivery of energy to its customers. These responsibilities to our customers must guide decisions both in day-to-day operations as well as in longer-term planning and investing. At the same time, new approaches to utility

compensation, such as performance incentives, can play an important role in encouraging innovative investment and operational decisions, and provide new benefits to customers.

As RI modernizes its energy system and pursues its energy and climate policy goals, the greatest benefits to customers are likely to be achieved when traditional cost-of-service regulation is combined with carefully-designed incentives geared at delivering new benefits and efficiencies to customers.

The Company has a long history of making investment and operational decisions to the benefit of customers under the current regulatory framework. Going forward, the Company's core business functions and investments in modernization of the electric system are best supported by continued reliance on cost-of-service ratemaking as the cornerstone of the regulatory framework. Optimizing the utility system to the long-term customer benefit will require new 'up-front' investment in excess of current investment levels. For the foreseeable future, utilities will continue to make large capital investments, and customers will benefit from the utility's ability to raise this capital at reasonable costs and on reasonable terms. Further, regulatory oversight of capital and operating expenditures ensures that utility investments align with customer interests and regulatory standards.

At the same, time, however, cost-of-service regulation 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. As states like RI grapple with integration of advanced technologies, DER, and pursuit of aggressive climate goals, creating an environment that fosters utility innovation around traditional functions as well as achievement of state goals has the potential to reduce costs and provide broad customer benefits. Modest but meaningful financial incentives focused on outcomes have the potential to encourage innovation and help utility regulation better mirror the outcomes of a competitive market where firms earn higher returns from innovating and providing products and services that deliver more value for customers. Providing incentives for the utility to deliver its core capital program (the Infrastructure, Reliability, and Safety plan - ISR) more efficiently, for example, can encourage the utility to innovate in manner that reduces utility costs over time. Incentives around the utility's delivery of regulator or policy goals intended to provide new customer benefits, such as peak reduction or GHG emissions reduction, can be designed to both reward the utility and ensure that customers receive the majority of benefits.

As the role of the utility evolves from a one-way provider of electric service to a more multi-faceted role, such performance-based regulation can complement today's utility business model, with a resulting framework that funds essential investment and efficient execution through cost of service, but also directs and incentivizes the utility to focus on outcomes that provide value to customers that would not be delivered through incentives provided by a purely cost-of-service regulatory framework. In addition, to the extent the utility provides new services connecting customers and third parties, market-based earnings collected from these parties may also contribute to utility compensation. However, the potential size of such earnings, and their ability to support utility cost recovery, remains untested.

2) What are ratepayers paying the utility for? How should it collect its revenue? Should its compensation differ according to each function?

And…

3) Do any of the future utility functions described here merit a particular type of revenue recovery mechanism?

The utility is accountable for the safe, reliable, efficient delivery of energy to its customers. Customers pay the utility for the services articulated under Question 1 of the section on utility functions. All of these functions must be done in way that provides value for our customers today and into the future and appropriately considers impacts on customer bills. Although the utility's role will continue to evolve, these activities will remain core functions of the utility.

The utility's costs, both capital and non-capital, should be recovered through rates that are designed to reflect cost-causation and promote equity and system efficiency.

The utility should recover revenue associated with its core functions through rates designed to align with cost causation and meet principles of equity and efficiency. Rates design should be sustainable as utility business models evolve. The Company emphasized the importance of these principles throughout the Docket 4600 proceedings. The current reliance on volumetric rates to recover most costs associated with distribution leads to four key problems: (1) significant cross-subsidization (between non-net metering customers and net metering customers, and between low load factor and high load factor customers), (2) inefficient use of the distribution system, (3) long-term risk to cost recovery due to continued upward pressure on rates as load declines or remains flat, and (4) inefficient integration of DERs.

As the grid modernizes, utilities, regulators, and stakeholders must consider how rate design, in combination with advancements in efficiency, demand response programs, and innovations in compensating DERs, can help the system evolve in an efficient manner to ultimately benefit all customers, while ensuring that costs are recovered equitably across all customers. In the long term, a transition to demand-based rates for demand-related components of distribution system costs, accompanied by time-varying rates by for electric supply, would address the challenges inherent in current rate design, while providing a sustainable rate design that encourages efficient use of the system. Implementing such a rate design, however, is not an immediate option, as it will require deployment of advanced metering technology. An outstanding question, therefore, remains as to how best deal with the challenges with existing rate design in the near term.

Public policy costs should not be avoidable and should be recovered equitably.

As noted in the discussion on utility functions, the utility is also charged with delivering certain public policy programs, the costs of which are typically recovered from customers through volumetric rates. These costs have grown under time, and under current rates, the costs associated with the state's energy efficiency and renewable energy programs comprise 11% of a typical (500 kWh/month) customer bill, with the vast majority of this customer's monthly contribution to these programs (98%) recovered on a volumetric basis. As discussed in the Docket 4600 stakeholder sessions, this recovery structure allows some customers (e.g., net metering) to dramatically reduce or even zero-out their contributions to these broadly beneficial programs. Options for more equitably recovering these costs should be evaluated, including potential recovery of some portion of these costs through a fixed charge.

SECTION 3. WHAT IS THE APPROPRIATE ROLE OF PERFORMANCE BASED REGULATION IN UTILITY COMPENSATION AND WHAT METRICS SHOULD DRIVE UTILITY COMPENSATION?

One alternative approach to compensating the utility is performance-based regulation which includes a multi-year rate plan and broad performance incentive mechanisms that tie designated financial rewards and penalties to specific performance metrics. Rhode Island already has significant experience with performance incentive mechanisms for specific topics, such as energy efficiency and renewable energy deployment.

Questions for Stakeholders on Multi-Year Rate Plans

1) **Should the utility be required to file multi-year business plans which forecast its business objectives and costs as a part of its distribution rate case? If so, what should be the period between rate cases?**

National Grid believes that customers, regulators, and the Company will benefit from a regulatory framework that remains sufficiently flexible to adapt to multiple futures. For this reason, the Company discourages adding new mandates or requirements around regulatory proceedings. National Grid is interested in engaging with the PUC and Division on the development of multi-year rate plans. The Company believes this is possible now under the current statutes and regulations without any changes required. Such a transition would require the Company, PUC, and Division to collaborate in order to agree to an appropriate process, but National Grid believes this is possible without the addition of a mandate. 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, with the potential for the period to be extended as processes, methodologies, and design are refined over time. It is also important to note that the development of performance incentive mechanisms will require the development of forward-looking targets informed by multi-year forecasts.

Questions for Stakeholders on Performance Incentive Mechanisms

1) There exist a range of policy goals to orient a performance based regulatory framework, including reliability, cost reduction, system efficiency, and greenhouse gas emissions reductions. Are there additional goals that should orient performance based financial incentives?

The Company believes that development of performance incentives is particularly valuable for two key categories of activities.

1) **Company activity that supports the efficient delivery of state policy goals.** While the Company already has incentives around energy efficiency, long term contracts for the purchase of renewable energy, and participation in ISO-NE's forward capacity market, additional incentives might be designed around greenhouse gas emission reductions, EV charging or deployment, or interconnection of distributed generation. Incentives are particularly important in cases where the Company is taking on new risk (e.g., via long-term contracts) in support of such goals.

2) **Company activity that provides broad benefits to customers or stakeholders that are not sufficiently encouraged under the traditional cost of service regulation**. For example, more efficient delivery capital expenditures can be supported by performance incentives. In addition, development of incentives should prioritize specific areas that provide clear savings or value to customers, such as coincident peak reduction, successful delivery of major information systems projects, or customer engagement.

While we note the focus of this proceeding is the Company's electric business, it is worth noting that similar considerations apply to our gas business, where incentives can be used to support gas pipeline replacement, targeting leak-prone pipes, or gas pipeline safety more generally.

2) What portion of the utility's revenue should be subject to performance incentive mechanisms? Should that portion change over time?

National Grid's view is that there is not a strong rationale for considering incentives in terms of a percent of utility revenue. Rather, incentives should be calibrated to allow customers to retain the majority of benefits while ensuring the incentives are material to the Company and its shareholders. That said, a magnitude in the order of 100 basis points of potential incremental revenue provides a reasonable starting point for evaluating appropriate earnings around a portfolio of outcome-based incentives.

Incentives should be designed such that the customer benefits associated with achieving the target exceed the costs of doing so. In National Grid's proposed earnings adjustment mechanisms (EAMs) in New York, for example, the proposed potential earnings were sized such that 1) they were justified by the net benefits to customers; and 2) customers retained the vast majority of benefits created, while still providing a sufficiently meaningful incentive to warrant the focus of National Grid leadership.

The size of the incentive must also consider whether the utility is expected to undertake new spending with cost at risk in order to achieve the incentive targets. To the extent that the utility is expected to take on additional costs that will not be recovered through rates, the expected value of the incentive to the utility will have to be larger than those costs. Where the activity being incentivized is supported by expenditures captured in the utility's revenue requirement, the incentive can be smaller, but still must be large enough to justify the attention of management and any internal resource reallocation that must occur.

Incorporation of performance incentive mechanisms into the regulatory framework should be gradual and should not impede a utility's ability to recover costs of (and with regard to capital expenditures, earn a reasonable rate of return on) prudent investments made in support of the utility's public service obligation to serve customers and comply with statutory requirements. This point is particularly important given that achievement of the state's policy goals around grid modernization, carbon emissions, and renewable energy integration are likely to require additional short-term investment by the utility, with the goal of providing sustained benefits to customers over a longer time-horizon.

The role of performance incentive mechanisms should be evaluated over time both in terms of their effectiveness in driving the desired utility behavior and policy goals, as well as interaction with the utility business model and their impact on utility earnings.

3) Are there any costs associated with new or old services which should be isolated from the utility's revenue requirement and made separately subject to performance incentives that place cost recovery at risk while creating the potential for the utility to earn more than the cost?

Given the significant interdependencies between the functions currently undertaken by the utility, a holistic view of the revenue requirement is typically most effective. However, to the extent that incentives are designed to encourage activity outside or beyond the utilities core functions to achieve policy goals and provide customer benefits, it may be appropriate for utilities to put some costs at risk in support of these earning opportunities, or otherwise take on additional balance sheet risk as is currently the case for power

purchase agreements. As discussed above, the expected value to the utility of this incentive would have to be large enough to justify the additional risk to the utility while providing an additional financial incentive to undertake the activity.

4) What is the appropriate balance between potential rewards and penalties? Should rewards begin as symmetrical with potential penalties? Should the relative size of penalties and rewards change over time as the utility gains experience operating in a new regulatory framework? Do existing performance based incentives provide a sufficient learning experience for customers, vendors and the utility?

Achieving greater levels of performance in support of state policy goals is likely to require incremental investments, redirection of Company resources, and new business approaches. To the extent that the utility is expected to perform in a new area with the goal of providing new benefits to customers through innovative approaches, incentives should be positive only to start. Assuming appropriately-designed incentives for activities providing new, positive benefits to customers, customers are better off the more that the incentives are awarded. For these types of benefits, use of penalties should be very limited. The effectiveness of incentives should be reviewed over time, with the potential for adjustments to size of the incentive and level of symmetry if justified.

While the Company, the Division, and the PUC have had meaningful experience with incentives around energy efficiency, long term renewable energy contracts, and gas supply optimization, it is important to recognize these experiences may inform but are not fully transferable to the design of new incentives targeting new outcomes or efficiencies. For outcomes that are new in terms of utility accountability, there is a strong rationale for beginning with upside-only incentives in order to establish performance-based incentives as a beneficial mechanism for both the utility and customers.

5) How should a potential enterprise-wide performance-based regulatory framework interact with existing performance incentives, such as statutory performance incentives for energy efficiency and renewable energy?

Given the starting point of today's regulatory framework, the introduction of new performance-based regulation is likely to be built on what exists today as opposed to a transformational new enterprise-wide framework. As new incentives are developed and overlaid on the existing framework, the relationship between the new and existing incentives should be evaluated for redundancy or potential contradictions. Development of an incentive framework should focus on targeted incentives around key outcomes of value to policymakers and customers, with an overarching earnings sharing mechanism if needed to help support an appropriate balance between value to the Company and customer benefits.

6) If a performance based plan is implemented through basis point rewards and penalties on the return on rate base, what range around the utility's allowed ROE should be used?

Absent a specific portfolio of incentives, it is difficult to gauge the appropriate size of their potential value. However, assuming a portfolio of multiple outcome-based incentives, 100bps is likely a reasonable starting point. Ultimately, two key principles should be considered in this determination. First, the potential incentive opportunity must be sufficiently large to both capture the attention of utility management and justify any incremental cost to the utility. Second, the total incentive opportunity should be commensurate to the net benefits of achieving the incentives' targets, and should allow customers to retain the majority of the benefits created.

7) What utility behaviors should Rhode Island be trying to change with performance based incentives? What do we want the utility doing tomorrow that they are not doing today under traditional rate regulation?

Under Question 1 of this section, the Company has identified specific areas where incentives are likely to produce outcomes valuable to the customer in the near term. However, incentives can potentially be designed around any outcome of importance to regulators. With that in mind, it is helpful to consider criteria for identifying utility behaviors that could warrant incentives. Development of incentives should:

a. Focus on activities that leverage a unique strategic role that can be served by the utility or in circumstances where there is a demonstrated market failure;
b. Produce significant benefits to customers and/or promote Rhode Island's energy policy goals; and
c. Apply to activities where the utility plays a distinct and clear role in bringing about the desired outcome.