Rhode Island Power Sector Transformation

Utility Business Model Principles and Recommendations

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DRAFT FOR STAKEHOLDER COMMENT

Introduction

As the architect of the local electric distribution system, the electric utility occupies a central place in the changing power sector. The functions the utility performs, the way it recovers its costs, and the incentives under which it operates create the *utility business model.*

The business model of Rhode Island's electric utilities is in need of change. Over the last 100 years, Rhode Island's electric utilities have developed in an environment in which demand for electricity consistently increased, technology changed incrementally, customers exerted little control over their electricity demand, and electricity flowed one-way from the utility to customers. Today, demand for electricity has plateaued, many customers generate their own power, electricity flows from customers as well as to them, technologies are being introduced at ever greater speeds, and the need to mitigate and adapt to climate change is real. In these new circumstances state policymakers must ask whether the utility business model continues to serve the public interest. The Power Sector Transformation process has defined the public interest:

- to control long-term system costs;
- to enhance customer choice;
- and to provide the necessary flexibility to incorporate greater clean energy resources

One indication of how today's utility business model fails to keep up with existing conditions and to advance the public interest is the efficiency of the electric distribution system. While most industries have become more efficient over the last few decades, leveraging information technologies to cut unnecessary expenses, Rhode Island's electric distribution system has demonstrated a system efficiency – defined as the ratio of peak to average demand -- of about 50 percent. On average, the utility uses only roughly half of the capacity it has built to meet peak demand, raising costs and highlighting the need for a new approach to align the utility's incentives with the public interest.

To address the new conditions we live in today, Rhode Island's electric utilities, like those in other states across the country, will need to develop significant new capabilities over the coming years to help all Rhode Islanders manage a transition to a cleaner, less centralized, and more resilient energy system. Electric utilities will need to augment the significant capabilities they have developed over the last 100 years in designing and deploying infrastructure with new capabilities. And like other industries, the utility will need to leverage information and communications technologies to benefit customers and shareholders. For the electric utilities to best serve Rhode Islanders, it will need to gather, analyze and leverage information that will allow it to better engage customers and to better enable other businesses to use the electric grid for new kinds of services. Whether as a platform for other service providers or as a customer-focused energy service firm, Rhode Island's electric utilities will need to leverage the information they can gather from the electric distribution system to become an information-driven enterprise. The transition to an information-driven utility will control long term costs, increase customer choice, and enhance the flexibility needed to incorporate more clean energy resources.

There are many potential commercial arrangements that may evolve in coming years to realize an information-driven electric distribution system. The regulatory framework should be flexible to allow market and technology developments to evolve, sorting out the commercial arrangements that will be most successful. It is the role of state policy makers and utility regulators to change the incentive structure for utilities such that they begin to develop the technological and organizational capabilities they will need if they are to continue to serve the public interest.

A key component of reform is the utility compensation framework. In particular, reform of the utility compensation framework should address:

"Infrastructure Bias". The traditional regulatory model for electric utilities, in which the electric utility earns a return on its investments in the system based largely on the cumulative depreciated cost of the prudent infrastructure it has deployed, may exert an "infrastructure bias" to deploy capital-intensive solutions. This occurs because the primary financial means through which the utility can grow its business and enhance earnings for shareholders is to invest in capital projects. This bias provides an incentive to seek more efficient solutions that do not depend on utility infrastructure investment. . In particular, distributed energy resources and grid control technologies offer new opportunities to provide reliable service with lower capital investment, reducing long-term system costs.

The utilities are required to maintain reliability and to assure that the system can provide service on the days of the year in the summer and winter when demand is at its highest. The traditional regulatory model for electric utilities, creates a bias regarding the manner through which the utility addresses this issue. Instead of seeking non-capital solutions that could reduce demand at its peaks, the utility's bias is to invest in more infrastructure. One of the primary causes of this bias is the compensation structure through which the electric utility earns a return based largely on the cumulative depreciated cost of the prudent infrastructure it has deployed. While this assures reliability, it has a negative impact as well, by creating a system in which a significant portion of deployed infrastructure is used for a small fraction of the year, increasingly the size and cost of the electric system.

Risk of Technology Obsolescence. In an age in which many business solutions depend on fast-changing technologies, the existing utility business model inhibits the utility from taking the kind of innovation steps that we expect from all businesses. The ability of the utility to continue recovering its costs depends upon whether the infrastructure or system component is still used to serve customers. Obsolescence will result in system components being removed from service. In turn, removing obsolete systems from service could result in the utility incurring a financial loss for the undepreciated portion of the investment. An overly cautious system leading to no experimentation and risk taking threatens Rhode Islanders with losing the opportunity to achieve innovation-sourced gains that have so shaped other areas of our life.

Data Connectivity. Similarly, a more modernized and dynamic electric system will depend on operation of data networks to allow the utility to gain visibility and control of the electric system. Many of the functions associated with operation of a data network are outside of the

electric utility's traditional area of operations and include strategically important, but not capital intensive, software, and "cloud services" components.

The electric utility will, in the future, need to perform functions beyond its traditional role, in particular related to the collection and analysis of information from its own distribution system and from its customers. The electric system of the twenty-first century will depend on operation of data networks to allow the utility to gain visibility and control of the electric system. However, today's utility compensation framework does not fully encourage the utility to develop the organizational structures and capabilities needed to undertake many of the information-oriented functions that it will be called upon to perform. Many of the functions associated with operation of a data network are outside of the electric utility's traditional area of operations and include strategically important, but not capital intensive, software and service components.

Utility functions could be grouped into three broad groups:

1. Core Reliability Function: The Core Reliability Function consists of those services that the utility has historically provided. They are the poles, the wires, the transformers, the fuse cutouts, the reclosers, the service drops, the substations, the transmission interconnections, and a multitude of other equipment. Tied to these assets are the operation and maintenance expenses associated with trucks, the line workers, the support staff, the buildings, the warehouses, systems, and all the administrative costs supporting this and much more. These assets and expenses probably make up the vast majority of the cost of the delivery side of the bill.

2. Platform-Facilitated Functions: This category covers functions that allow the utility to serve as a platform to facilitate the transactions and businesses of others on the grid. These functions may include, but are not limited to, energy efficiency measures, management of consumer energy consumption, customer usage data gathering, management of customer information, provision of information to policy makers, and facilitating the connection of distributed generation to the system, among others. The platform function would be for the utility to facilitate the means for third parties to manage energy related transactions that take place among participants, such as sale of energy from distributed resources from one location to the other, aggregating demand response among groups of customers, and providing the means for customers to join together to advance renewable energy projects. These functions may become a source of revenue for utilities independent from the end-use customer.

3. Mixed services. This category of functions would include ownership and maintenance of electric meters, billing system management, making service connections, and other functions that relate to direct interactions between the utility service provider and the consumers receiving basic utility services. Some of these functions clearly can be performed by third parties on behalf of the utilities. One example is ownership of communication components that may be associated with advanced metering infrastructure. However, these are not services that can be set at a "market price" for electric customers, except to the extent that the communication function (beyond metering of consumption for billing purposes) is used to create a new service.

Regulatory Context

The current utility business model in Rhode Island is based on a compensation framework of cost-of-service ratemaking with a return on capital with a one-year forward test year and revenue decoupling. This 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. The problematic aspects of the current business model include:

1. *Rate case period*. The current regulatory model sets rates for only one year at a time. This means that during the second or third year following a rate case, as costs change quickly, there is no means for the utility to recover them. As a result, utilities either do not innovate in order to avoid incurring the costs (in order to maintain earnings) or file rate cases more frequently. Either of these decisions impede long-term planning and provide a disincentive for the utility to incur non-capital expenses in one year that do not yield savings until later years. As non-capital expenses become necessary to address the new role of the utility, the utility's earnings suffer, and more rate cases are the result... This framework can erode the utility's incentive to improve performance and contain costs. Utilities have little incentive to reduce or optimize operating costs or capital costs. Distributed Energy Resources (DERs) are one way that utilities can reduce operating and capital costs. Yet, if the only way the utility can advance DERs is to file frequent rate cases, it creates an inefficient system with disrupted long-term planning.
2. *Incentive to build rate base*. Utilities have an incentive to increase their rate base because this will lead to growth in earnings potential. Utilities can increase rate base by making capital investments in conventional distribution technologies. This creates a disincentive to promoting DERs, which typically do not require capital investments and can postpone or avoid capital investments that do build rate base.
3. *Reluctance to invest in innovative technologies*. Utilities are reluctant to invest in new, untried, or innovative technologies because of risks associated with post-investment prudence reviews. This can occur when it is apparent that a particular technology is undergoing rapid change. The utility hesitates out of fear that it may be too easy for regulators to second-guess an investment in a technology when after-the-fact evidence emerges that the technological solution was likely to change quickly. This can hinder a utility's incentive to invest in certain DERs or technologies that support them, such as advanced metering infrastructure, data collection and management systems, and communication systems.

The National Grid Business

National Grid is the electric and gas distribution utility for most Rhode Islanders. It is a wholly-owned subsidiary of "National Grid plc," a global energy company based in London, England that owns regulated and unregulated energy-delivery businesses in the United States and the United Kingdom. [1]

[1] The technical legal name of the Rhode Island utility is "The Narragansett Electric Company." However, for corporate branding purposes, all of National Grid plc's regulated companies in the U.S. – including Narragansett Electric – do business under the same name of National Grid.

In Rhode Island. National Grid provides electric distribution service to approximately 500,000 electric customers across the state. The electric service area comprises nearly all of Rhode Island and the company is also the only natural gas distribution utility in the state, providing service to approximately 264,000 natural gas customers.[2] National Grid also owns the high voltage transmission facilities that cross the state in many areas. These transmission assets are a part of the overall regional transmission system that is controlled by ISO New England and regulated by the Federal Energy Regulatory Commission.

Since the electric utility business was restructured in Rhode Island in 1996, National Grid's primary business has been to deliver the electricity produced by non-affiliated generators in the regional market[3]. and maintain local service reliability. The service and rates associated with the distribution of electricity is regulated by the Rhode Island Public Utilities Commission (PUC). While National Grid sells commodity electric supply – referred to as "Standard Offer Service" – this commodity service is only supplied to customers who have not otherwise selected a third-party supplier for their power and the company earns no profit on the sale of commodity electric supply.

National Grid's combined operating revenues for all of its consolidated electric and gas businesses in Rhode Island were approximately $1.26 billion in fiscal year 2017.[4] The total net investment (i.e., rate base) that National Grid has made in Rhode Island is significant as well – over $2 billion, —$1.3 billion of which is regulated by the PUC.[5] Of the $1.3 billion in rate base, approximately $665 million is the electric distribution system that provides electric service directly to consumers. The total net investment by sector in Rhode Island is set forth below.[6]

Total Rhode Island Rate Base by Sector

Electric Distribution	665,000,000
Gas Distribution	640,000,000
RI PUC regulated Total	**1,305,000,000**
Electric Transmission	697,000,000
Total Rate Base (all sectors)	**2,002,000,000**

Source: National Grid 2016/2017 Full Year Results Statement

The global parent company, National Grid plc, has measured the value and performance of the U.S. regulated businesses – including National Grid in Rhode Island – by investment growth and the annual earnings of each of the U.S. entities.[7] Growth is measured in terms of increases in rate base from year to year. Earnings is measured in terms of the "return on equity" earned on rate base

[2] The number of electric and gas "customers" represents customer accounts. There are many entities and individuals who may have more than one account.
[3] CITE RESTRUCTURING ACT 1996.
[4] Audited financials found at: http://investors.nationalgrid.com/~/media/Files/N/National-Grid-IR/reports/2017/neco-march-2017.pdf page 4.
[5] As typically categorized in utility regulation, the investment is stated in terms of "rate base." The rate base is the total investment made by shareholders, less accumulated depreciation.
[6] Source: http://investors.nationalgrid.com/~/media/Files/N/National-Grid-IR/results-centre/full-year-results-statement-2016-17.pdf pages 33-34.
[7] See, for example: http://investors.nationalgrid.com/~/media/Files/N/National-Grid-IR/results-centre/full-year-results-statement-2016-17.pdf pages 3, 4, 33 & 34; and http://investors.nationalgrid.com/~/media/Files/N/National-Grid-IR/presentations/2017/fy-2016-17-presentation.pdf pages 17, 33, & 35.

in each fiscal or calendar year (i.e., earned "ROE"), compared to the ROE that is stipulated by the regulator in rate cases (i.e., allowed "ROE").

In calendar years 2014 and 2015, National Grid in Rhode Island reported earnings to its shareholders that met or exceeded its allowed ROE for both its electric and gas distribution businesses. For Fiscal Year 2017, however, the company experienced a decrease in earnings, reporting earned ROEs of 7.7% and 9.4% in the electric and gas distribution sectors, respectively, compared to an allowed ROE of 9.5%.[8]

The investments made by National Grid in its utility infrastructure are financed in two principal ways – issuances of debt and infusions of capital from equity holders. The ratio of equity to debt varies from year to year. Rhode Island regulators have typically found a ratio of approximately 50% to reflect an appropriate equity ratio for the electric and gas distribution businesses (consistent with industry standards), and the calculated ROE of the company for its distribution businesses assumes this in the capital structure. However, the actual equity ratio (which includes capitalization of transmission investments not regulated by the PUC), is much higher than 50%, according to the most recent auditor's report for the fiscal year ending March 31, 2017.[9]

Since a significant amount of the investment made by the company is funded through debt from bond issuances, the debt rating of the individual National Grid entity is important to assure the lowest possible bond interest rates which are ultimately funded by ratepayers. In that regard, the company has maintained a reasonably healthy debt rating of A3 from Moody's and A- from S&P, as reported by National Grid.[10] In the context of utilities, the debt rating often depends in large part on the perception of the rating agencies regarding the prevailing regulatory cost-recovery rules of the state regulator overseeing the rates of the utility being rated, along with economic conditions within the state, among many other factors.[11] The current ratings of National Grid appear to reflect a relatively positive outlook, signaling to bond investors that the likelihood of repayment is very good, reflecting confidence in the company and its regulatory environment to deliver sufficient revenue for this purpose. Maintaining the confidence of investors, while potentially expanding their expectations for performance incentive compensation, is an important component of utility business model reform.

Peak Management

One consequence of the existing utility business paradigm is an electric grid built to meet peak demand. Chart 1 presents the peak hourly demand for the last ten years for Rhode Island displayed as a single chronological year. The chart highlights the seasonal summer peak and also the few hours which drive overall system peak for which the electrical grid must build capacity.

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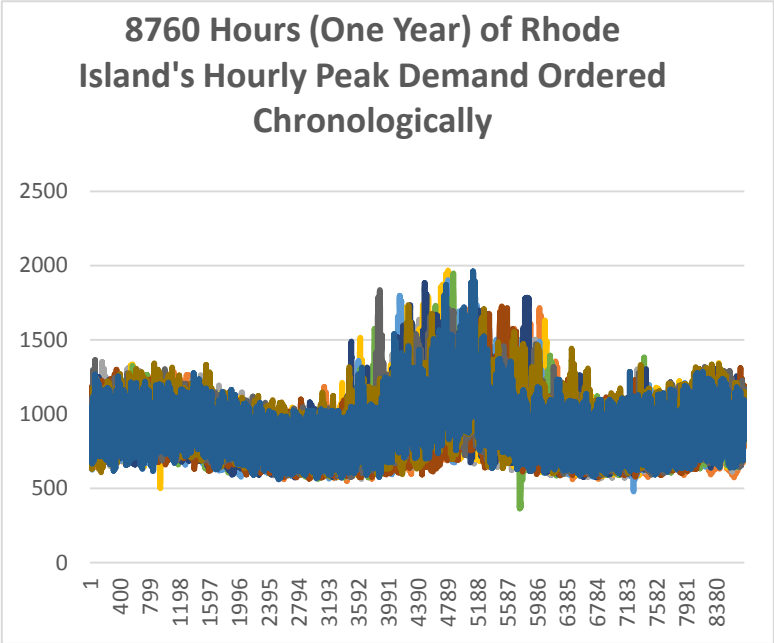
[8] See page 33 of the National Grid plc results statement at: http://investors.nationalgrid.com/~/media/Files/N/National-Grid-IR/results-centre/full-year-results-statement-2016-17.pdf . The earnings reported to shareholders differ from earnings reported in filed regulatory reports with the PUC due to different accounting methods employed in the calculations.

[9] http://investors.nationalgrid.com/~/media/Files/N/National-Grid-IR/reports/2017/neco-march-2017.pdf

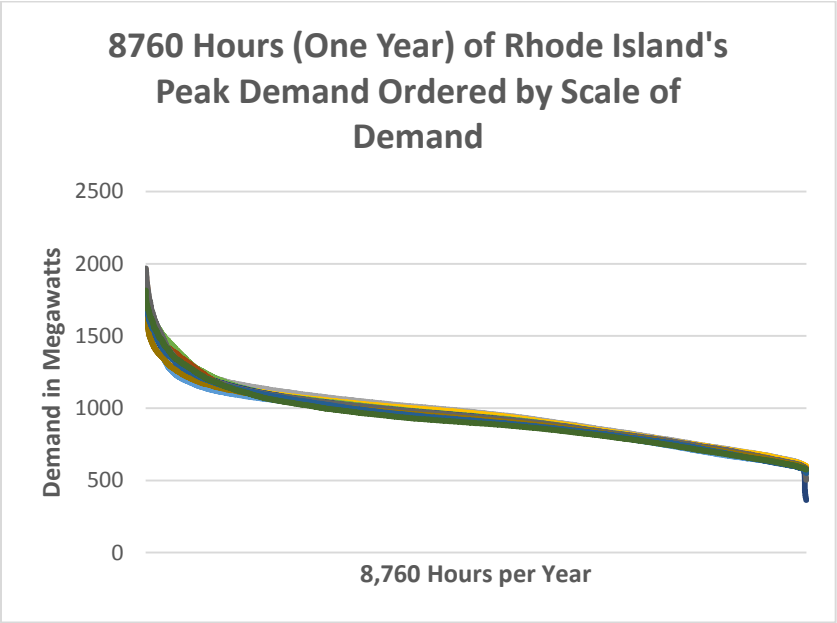
[10] http://investors.nationalgrid.com/debt-investors/credit-information.aspx

[11] See Standard & Poor's publication at: http://www.maalot.co.il/publications/MT20131127143752a.pdf



The same data appears in Chart 2 organized by the number of hours in which each peak is reached. The left side of the chart shows that a very few number of hours drive the system's capacity requirement.

Chart 2.



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In response to the context of the current utility business model – a cost of service regulatory framework with some additional performance incentive mechanisms, existing regulatory tools provide significant potential to reform the incentive structure of the distribution utility.

Rhode Island's Existing Performance Incentive Context

Over the last decade, Rhode Island has recognized that cost of service regulation is not always, in itself, adequate to achieve state energy policy objectives. For example, the 2014 Renewable Energy Growth Program[12] , the 2009 Long Term Contracting Standard for Renewable Energy[13] and the 2006 System Reliability and Least-Cost Procurement [14]laws each establish topical, performance-based incentives to correct perceived gaps in cost of service regulation. Reform of the utility business model can build upon the success of these existing performance-incentive mechanisms.

In recognition of the potential for distributed energy resources to provide less capital-intensive grid solutions, the Rhode Island General Assembly has established a series of performance incentive mechanisms (PIMs) focused on particular performance areas. The following are the sections of the Rhode Island General Laws which set forth either a provision for the PUC to calculate a performance based incentive or issue an expressed percentage for remuneration to the Company for its implementation of and participation in a particular program.

- **R.I. Gen. Laws § 39-1-27.7 (e) System Reliability & Least Cost Procurement-** In accordance with the statute the PUC is authorized to formulate a performance based incentive considering the level of success of National Grid in reducing the cost and variability of electric and gas services through procurement portfolios. In 2013 as part of Docket 4366, the PUC ordered that the company could earn incentives starting at 75% savings target achievement and can continue to earn an incentive up to 125% for both electric and gas programs.[15] In 2011, the PUC ordered in R.I.P.U.C. Docket 4295 that the Company was entitled to earn an incentive of 10% of all funding secured from outside funding sources by National Grid for implementation of the EE Plan.[16]

- **R.I. Gen. Laws § 39-26.1-4 Financial Remuneration & Incentives-Long Term Contracts & Distributed Generation Contracts-Newly Developed Renewable Energy Resources-** The electric distribution company shall be entitled to financial remuneration and incentives for

[12] R.I.G.L. § 39-26.6

[13] R.I.G.L. § 39-26.1

[14] R.I.G.L. § 39-1-27.7 e.

[15] *See*, Attachment 1, 2017 EE Plan p. 29, IX Incentive, Shareholder Incentive Target is 5% (equals a 100% achievement) of $88.5 million dollar spending budget for a total incentive of $4.4 million dollars on the electric side (Attachment 5, Table E-9). The shareholder incentive for the 2017 EE Gas program is based on 5% of a $27.7 million dollar spending budget for a total incentive of $1.38 million dollars *Id.* (Attachment 6, Table G-9).

[16] It is not clear how much of an incentive sum, if any at all has ever been earned by National Grid by reason of this particular incentive.

accepting the financial obligation of the long term contracts (LTC) and shall be entitled to **2.75%** of the actual annual payment made under the PPA for projects reaching commercial operations.[17] The incentive provisions of the LTC and DG statutes will require ratepayers to pay incentives to the electric distribution company of over $50 million dollars over the life of the PPA's executed with Company by owners of renewable energy facilities. These payments will be over and above the Company's ROE.

- **R.I. Gen. Laws § 39-26.6-12 (3) Renewable Energy Growth Program (Feed In Tariff)-For 160 MW of Renewable Energy-** National Grid is required to enroll 160 MW of nameplate Renewable Energy over a five (5) year period. This program commenced in mid-2015. The electric distribution company is entitled **to earn an incentive of one and three-quarters percent (1.75%)** of the annual value of all performance based incentives issued to distributed generation facilities.[18]

- **R.I. Gen. Laws § 39-1-27.7 (e) Incentive for System Reliability & Least Cost Procurement** - In 2017, if National Grid meets its EE Targets of 100%, the gas and electric shareholder incentive will be $5.7 million. It met 100% of its 2016 EE targets and earned $5.6 million dollars.

- **R.I. Gen. Laws § 39-26.6-12 (3) Incentive for Renewable Energy Growth Program -** The incentive earned by National Grid for the RE Growth Program year ending March 31, 2017 was $31,873 (1.75% x $1,821,337 estimated PBI Payments) however, the projected cumulative incentive over the life of the RE Growth program is expected to yield $19 million to shareholders of National Grid. The shareholder incentive for the SolarWise Program has not been reported as of this date.[19]

Table 2 presents a preliminary analysis of the scale and scope of these existing financial incentives. The incentives, which are designed to accrue to shareholders, incent the utility to undertake activities that are beneficial for ratepayers. Although these incentives are designed as a percentage of the cost, the most comparable measure is to value the incentive as a share of the utility's return on investment. For this comparison, 100 basis points is 1% return on investment). Table 2 indicates that current incentives total roughly 44 basis points, out of a total of the over 950 basis points that represent the utility's allowed rate of return[20]

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[17] *See,* Attachment 2, Narragansett Electric Co., Long Term Contracting For Renewable Energy Provision, Tariff R.I.P.U.C. No. 2174, Sheet 1. *See also,* Attachment 3, Contract Incentives & Remuneration LTC & DG, Table pgs. 1-12 RIPUC Docket 4371 Attachment PUC 10-2 (a)–(b), January 5, 2017.

[18] *See,* Attachment 4, Renewable Energy Growth Program Cost Recovery Provision, Tariff R.I.P.U.C. No. 2176, Sheet 1.

[19] *See,* Attachment 5, RE Growth Summary of Net Costs for Program Year ending March 31, 2017, R.I.P.U.C. Docket 4626; *See also, Id.* RE Growth Summary, Line (23), Attachment RR-1, p. 3-3, R.I.P.U.C. Docket 4589-A.

Table 2. Comparison of Existing Incentive Mechanisms for 2017

Program	Program Costs (2017$)	Shareholder Incentives				
		(2017$)	(% of cost)	(basis points)	(% of net income)	
EE - Electricity	88,511,000	4,425,550	5.00%	24	4.5%	
EE - Gas	27,751,000	1,387,550	5.00%	8	1.4%	
SRP	400,300	20,015	5.00%	0	0.0%	
Long-Term Contracts	72,275,022	1,987,563	2.75%	11	2.0%	
DG Standard Contracts	7,063,354	194,242	2.75%	1	0.2%	
RE Growth DG Facilities	1,821,337	31,873	1.75%	0	0.0%	
Total	197,822,013	8,046,794	4.07%	44	8.1%	

Comments from Stakeholders

Stakeholders offered a range of views on utility function, utility compensation, multi-year rate plans, and performance incentive mechanisms.

Utility Functions:

All commenting parties agree that the utility should function as a distribution system platform provider that enables third-party companies to own and operate distribution-side services, while different views were expressed on the utility role in providing non-monopolistic services. The company wants to be allowed to compete in emerging services, while many commentators want the utility to only serve as a market enabler and be restricted from serving non-monopolistic functions. Because the utility should ensure non-discriminatory access and seamless integration of DER and other clean energy resources, the third-party providers are concerned this will be hindered if utility is competing with third-parties to provide those services. A consortium of clean energy developers want the distribution utility to be required to divest or separate from related companies that perform functions that are not natural monopoly distribution functions. The utility wants to operate, at least initially, the customer engagement portal with services from utility and third-parties. No stakeholders expressed disagreement with the utility owning the customer engagement portal.

Divergent views are expressed on the role of the utility in owning and operating or distributed energy resources. Several stakeholders questioned if the utility should administer most of the energy efficiency or DER programs. The utility would like to own the smart meters, while third-party providers want to operate advanced meters. Some stakeholders are agnostic about the utility owning EV charging infrastructure and some are strongly opposed because they see it as unnecessary and duplicative. The utility wants to own and operate smart grid meters, while others want third parties to operate advanced meters. Some commentators expressed interest in allowing, incenting or requiring the utility to outsource functions of administering DER programs (e.g. net metering) to a SaaS provider. One stakeholder wants the utility to use demand response as a primary tool and not as a last resort tool.

Most stakeholders expressed a clear desire for the utility to make customer and system data easily sharable with customers and third-parties, including conducting an open and transparent

distribution system planning. Commentators noted the need to balance data access with confidentiality.

Reliability, safety, and customer responsiveness should remain the utility's core functions, says the utility. Other stakeholders agree on reliability and safety but think the utility's core function on customer responsiveness is not needed since they want the utility to exclusively serve as a grid system operator.

Several commentators support utility-third party partnership models for shared communications infrastructure, advanced meters, and data analytics. One stakeholder wants the PUC to consider turning operations of an enhanced communications and electrical system to a semi-government agency.

Many comments about the utility business model functions focus on designing the broader electricity market structure. Most commentators want to enable third party energy developers to participate in grid services directly and as contractors to utility via PPA-like agreement. Some noted it is important to clearly define the separate role of enabling infrastructure versus the provision of services themselves. Regulations should focus on a transparent structure that allows coexisting business entities. The costs and values of network administration roles should be clarified. The regulators should fully value DERs and carbon pricing in resource planning.

Utility Compensation

Most commentators agreed that the utility should increasingly be compensated through performance based compensation, rather than on their inputs or investments. Most stakeholders said most of the utility's roles can be compensated under performance based structure. The utility wants a combination of cost of service regulation and incentives for new services. The utility thinks that the potential to reduce allowed ROE for PIMs the potential value of new incentive earnings would have be substantially more than any corresponding reduction in ROE to maintain investor confidence, and they prefer a cap on total earnings from combined ROE and PIMs with a shared savings mechanisms. One proposal offers cost trackers to continue aiming to clarify performance incentive mechanisms to be developed by the end of the first multiyear rate plan. A stakeholder proposes cost trackers only for factors outside of the utility control.

A consortium of clean energy developers wants the utility to have a serious financial incentive to transform into a platform facilitator. Existing investments should be compensated on a cost basis calculated over an amortization period for a specific investment including a small cost of capital consideration. In the long-term, compensation for overhead and profit should be provided only on a performance basis. A third-party provider wants the utility to be compensated for empowering customers and non-utility market participants, demand management, and reducing carbon intensity.

Several commenters expressed interest in capital and non-capital expenses being recovered more equitably to encourage system efficiency. To level the playing field for non-capital strategies – both utility-owned and third-party owned, the utility should be compensated equitable for both types of spending. Performance incentive mechanisms and revenue caps should encompass capital and operational expenditures. The proposal for ROE and innovative utility partnerships needs more refinement.

Shared saving mechanisms that give customers a larger share of the upside and smaller side of the downside depending on how the utility performs. One stakeholder proposed incenting the utility for reducing customers' energy costs through distributed resources – with a larger incentive for helping low-income customers in which utility bill is a larger share of consumer's income.

Different views were expressed on the ROE adjustment, with some accepting it so long as it is symmetrical. Some questioned how they work if taken out of ROE.

Caution was expressed from diverse stakeholders on utility charging fee for data, both from third-party providers (regarding smart meter data) and from the Utility (regarding EV integration because of low market demand).

Before designing utility compensation, carefully define the role of the utility, especially for EVs. Several stakeholders stressed the need to define utility functions before compensation. A utility's ability to generate revenue through EV subscription fee services hinges on its ownership of the equipment, so the state needs to consider if it should be encouraging ratepayer funded equipment in a competitive market.

Most stakeholders agreed on the need to align public policy goals with utility compensation. The state could create utility incentives for: higher system utilization, value creation, local energy solutions, greenhouse gas reduction, and consumer protection. The regulators can establish performance criteria for investment efficiency and technology utilization to mitigate obsolescence.

Address conflict of subsidiary companies. Some stakeholders asked to address the inherent conflict for business units that compete with each other and owned by the parent company by considering not allowing utility to joint ownership of electric and natural gas utilities as well as transmission and distribution companies.

Multi-year Rate Plans

All stakeholders expressed strong support for an extended rate plan because it will create a powerful cost efficiency incentive for both capital and operational expenses, since the utilities may reap more benefits. Some stakeholders would support this if done with a stakeholder developed IRP and earnings sharing mechanism. Most stakeholders, including the utility, favor a three-year rate plan.

Reccomendations emphasized that the rate cap must be set carefully. Some recommend a revenue cap applied across both operational and capital expenses. One stakeholder asked the PUC to consider how revenue cap and decoupling work together.

Diverse stakeholders are concerned with shifting the attrition relief mechanism to an index. Some say it should be considered in the context of refining the current regulatory mechanisms including forecasts and decoupling, rather than moving to an index. A hybrid approach may be appropriate down the line. The utility believes it should be based on its forecasts as more accurate but is open to evaluating potential index-based mechanisms. Unforeseen changes can be resolved through a reopener, note some.

Performance incentive mechanisms

Wide support for PIMs were expressed as a way to ensure service quality and policy outcomes, especially as a counterbalance to the cost-reduction pressure created by the multiyear rate case. One stakeholder expressed concern about the role of PIMs replacing the standard regulatory expectation. Most expressed a desire for PIMs to be used for outcomes that are not ordinarily in the utility's financial interest. The PUC should focus PIMs on creating new consumer values, said one stakeholder.

Suggested PIMs cover the categories of customer equity, system efficiency, and environmental benefits. Specific PIMs are suggested for: security, reliability, asset utilization, non-monetized benefits such as environmental goals, SRP targets, non-wires alternatives, DER integration, stakeholder participation, proactive capacity enhancements. Incent areas that stakeholders have already identified as priority areas for performance regulation, such as SRP targets and avoiding wires capital investments. A critical element to track is transactional metrics related to specific actions taken by customers and third parties. Several stakeholder

Metrics will help track multiple areas and a smaller set of PIMs would be appropriate. Collect the data for a year and then develop appropriate incentives with financial consequences.

PIMs should be large enough to have desired effect on utility behavior but capped to protect consumers. Different views were expressed on how to weight the PIMS. Some suggest weighting PIMS towards outcomes that will reduce capital expenditures and symmetrical incentives. Others suggest the results of a Docket 4600 cost benefit valuation analysis would be a reasoned basis for weighing the three categories of metrics. If that analysis is not ready, equal weight could be given to each category of metrics.

Symmetrical incentives with rewards and penalties are supported by several stakeholders. Some suggested awarding incentives as a fixed sum rather than a change to ROE.

Recommendations

The DPUC and OER see the steps outlined in this proposal as a move in the direction towards comprehensive performance based regulation (PBR) where the utility's business model is foundationally aligned towards public interest while still fairly compensating its shareholders.

PBR describes a set of regulatory tools aimed at aligning utility performance with outcomes favorable to customers and the public interest. The two primary goals of PBR mechanisms are to: 1) improve performance of non-monetized outcomes such as customer satisfaction, air emission reductions, and system reliability; and 2) stabilize utility bills by addressing economic inefficiencies of cost of service regulation,, by mitigating the rising trajectory of energy costs. The policy recommendations provided in this report take steps to address each of these two functions.

The first goal of improved performance of outcomes is addressed through a set of performance incentive mechanisms that offer financial incentives based on performance against defined metrics.

The second goal of stabilizing utility bills by improving economic efficiencies is addressed through the proposal of a multi-year rate plan that sets a revenue cap creating an incentive for the utility to more effectively manage costs and share the savings between its shareholders and customers.

Recommendation 1.1 Require National Grid to Submit a Multi-Year Rate Plan

Multi-year rate plans (MRPs) are a ratemaking construct designed to strengthen utility financial incentives to operate efficiently, make sound investments in capital and non-capital expenditures, and ultimately pass cost savings on to customers.[21]

During a transitionary moment in the utility industry, changing the rate case process to one in which the utility must set forth a multi-year plan for operating its distribution business is an important change to obtain the necessary regulatory oversight. Although about half of the rates relate to non-controllable costs that are subject to cost trackers, there remains a substantial part of the distribution business costs that is addressed in the rate case itself through base rates that an MRP would address. These costs will change over time as the industry changes as well. It is this portion of costs that is most relevant to the multi-year rate case and, relevant to how the business of the utility may change (outside of, or in concert with, the legislative mandates). It represents most of the costs needed to maintain reliable distribution service for the distribution customer base. Equally important for the Company, the rate case sets the ROE that is used in the ISR rate-setting processes prospectively. More broadly, an MRP would provide a regulatory tool to assure the utility's projected cost incurrence is consistent with the intent of the new public policies that will take time to implement.

The components of the Multi-Year rate Plan proposed here include:

Rate plan period

The MRP should cover a 3-5 year period. This means that National Grid will not be allowed to request a rate case for these three years. The Company should file a Business Plan to cover all

[21] For a very useful description and discussion of MRPs, see Lowry et. al., *State Performance-Based Regulation Using Multiyear Rate Plans for U.S. Electric Utilities*, Grid Modernization Laboratory Consortium, July 2017.

initiatives and all costs during this three-year period. In the future, National Grid will file a new rate case and business plan to cover the subsequent period. A rate plan period that is that any shorter than three years will provide little efficiency incentive for National Grid. The MRP could be longer than three years, but for the first MRP, a shorter period will allow lessons to be quickly learned and factored into a future plan. A period longer than five years might be too risky for customers.

Business Plan

The core of the MRP depends on a Business Plan that should include the Company's proposal for all costs that it expects to incur during the three-year rate plan. The Business Plan should represent a system-wide integrated distribution plan, incorporating the recommendations of the Rhode Island distribution system planning work stream. The goal of the Business Plan should be to identify the least-cost portfolio of distribution system investments, considering both distribution infrastructure investments and distributed energy resources, while recognizing reliability, statutory, and non-discretionary constraints. The Business Plan should incorporate all the analysis that is currently done in the ISR, but for a full MRP period. It should also incorporate the evolving initiatives under the System Reliability Procurement (SRP) process, as well as any other DER initiatives underway.

National Grid should develop the Business Plan, and allow for robust stakeholder input, before and during the development of the Plan. The stakeholder input process should be developed in detail, as this MRP straw proposal moves forward. This approach will enable the Commission, the Division, OER and other stakeholders to provide direct guidance on the Company's initiatives and capital investments, including those related to grid modernization, DERs, and other innovative developments.

Cost Recovery: Capital Costs

The capital costs included in the Business Plan should be used to set rates for each of years in the rate plan and cover a similar period of years. Post-rate case review of the capital costs would still take place annually through the Infrastructure System Reliability (ISR) proceeding. However, any changes in capital investments should be limited in the ISR process to only those matters that result from events or issues crucial to system reliability that were not reasonably foreseeable at the time the MRP was implemented. Absent a special issue identified in the annual ISR, however, under this MRP, there would be no reconciliation of actual to budgeted costs. If the Company spends more than was budgeted, then it absorbs the difference; if it spends less, then it keeps the difference. This approach provides the Company with needed capital to implement the Business Plan, and the certainty that the Commission will allow for recovery of capital costs associated with innovative projects. The lack of a reconciliation helps provide incentive for the Company to spend efficiently. In turn, the Company gets pre-approval of its capital investments.

Cost Recovery: Non-Capital Costs

Non-capital costs included in the Business Plan should be used to set rates for each of the years in the rate plan. There will be no reconciliation of actual to budgeted costs. If the Company spends more than was budgeted, then it absorbs the difference; if it spends less, then it keeps the difference.

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Earnings sharing mechanism

An earnings sharing mechanism (ESM) should be established to protect both customers and the Company from extreme outcomes. The ESM should measure the resulting ROE after the PIM revenues are applied for the given year. This prevents manipulation or perverse incentives from playing the PIMs off of the MRP.

A deadband of 100 to 200 basis points should be set around each side of the allowed ROE. This is a relatively broad deadband, to reflect the fact that PIMs could bring the actual ROE above the allowed ROE. Profit sharing above that deadband should be customer/utility = 50/50. This allows the Company to earn a relatively large amount of profit above the deadband, so as to maintain a relatively strong incentive for the Company to pursue the PIM targets once it reaches this range of ROE. Loss sharing below that deadband should be customer/utility = 20/80. This requires the Company to absorb most of the losses if the ROE turns out to be really low, so as to provide a strong incentive to comply with the Business Plan and achieve the PIM targets.

Recommendation 1.2 **<u>Performance Incentive Mechanisms</u>**

Performance Incentive Mechanisms are intended to encourage the utility to achieve specific objectives in specific performance areas. Most PIMs in place in the US today only provide financial incentives for a small number of performance areas, and therefore have a small impact on the utility's overall financial performance. In order to meaningfully counteract the utility's incentive to build rate base inefficiently, it is necessary to establish significant, coordinated financial incentives in both the MRP and the PIMs. If the financial rewards available from PIMs are large enough and based on achievable metrics and targets they can significantly enhance the revenues needed to earn attractive returns.

The following suite of performance incentive mechanisms include financial incentives and reporting-only metrics. They are arranged in three broad groups designed to address a range of utility actions. The first area of performance incentive mechanism is **System Efficiency**, designed as a broad metric to achieve savings for ratepayers from the utility controlling long-term utility costs. The second area is **Distributed Energy Resources**, which includes targeted incentives for a range of distributed energy resources that require utility action to implement. The third area is **Network Support Services** which includes actions that the utility will need to accomplish to demonstrate capabilities essential for the future utility.

PIMs can be used to mitigate the infrastructure bias described above, by replacing some of the revenues that the Company would otherwise have earned from its allowed ROE with the revenues from the PIMs. This could be achieved by setting the allowed ROE at the lower end of the range of reasonable ROEs proposed by the Division in the rate case. The Company would then be able to earn additional revenues from the PIMs to make up for the relatively low ROE.

System Efficiency

These broad metrics are designed to be outcome oriented with financial incentives that are sufficiently large to affect the company's decision making.

<u>Monthly Transmission Peak Demand</u>

Description: To encourage the utility to reduce transmission peak demand, in order to reduce its share of New England transmission costs.

Metric: Narragansett Electric contribution to the ISO-NE coincident peak, by month.

Target: TBD.

Incentive: TBD.

Forward Capacity Market Peak Demand

Description: To encourage the utility to reduce annual demand in the Forward Capacity Market peak demand, in order to reduce its distribution costs.

Metric: Narragansett Electric peak distribution demand, annual.

Target: TBD.

Incentive: TBD.

Time-Varying Rates

Description: To encourage the utility to promote customer participation in time-varying rates in order to influence consumption patterns to track temporal patterns of system cost.

Metrics: (1) Percent of customers on TVR, by customer sector, by year. (2)

Target: TBD.

Incentive: TBD.

Time-Varying Rates – EV

Description: To encourage the utility to promote customer participation in time-varying rates in order to influence consumption patterns to track temporal patterns of system cost and avoid adverse system effects from EV growth.

Metrics: Percent of customers with EVs enrolled in a time-varying rate, by month and by year.

Target: TBD.

Incentive: TBD.

Distributed Energy Resources

This category of performance incentive mechanisms includes existing mechanisms and several new mechanisms designed to incent cost-effective distributed energy resources.

Energy Efficiency --Electric

Description: To encourage the utility to optimize the use of the electric energy efficiency programs in order to maximize deployment of cost-effective energy efficiency.

Metric: MWh and MW of electricity savings.

Target: Set in annual EE Plans.

Incentive: Based on MWh and MW saved, up to 5% of program budgets.

Long-Term Renewable Contracts

Description: To encourage the utility to implement renewable long-term contracts in order to achieve state renewable energy targets and minimize carbon in the generation serving RI. This is set by statute.

Metric: Payments made through PPAs.

Target: None.

Incentive: 2.75% of actual payments made through PPAs.

RE Growth DG Facilities

Description: To encourage the utility to support RE Growth facilities in order to support state renewable energy policy. This is set by statute.

Metric: Incentives issued to DG owners.

Target: None.

Incentive: 1.75% of incentives issued to DG owners.

SRP / NWA (Access to Distribution System Data)

Description: To encourage the utility to develop non-wires alternatives in order to reduce distribution system costs.

Metric: Provide distribution system data to empower customers and third parties to identify opportunities to install distributed energy resources in constrained areas of the grid.

Demand Response (non-SRP)

Description: To encourage the utility to design and implement successful demand response programs in order to manage costs associated with peak demand.

Metrics: (1) percent of customer load served annually, by customer class; (2) annual capacity savings (MW); (3) program costs per capacity saved ($/kW)

Electric Vehicles

Description: To encourage the utility to assist with the development of EVs and charging stations in an efficient and cost-effective manner in order to meet state transportation and climate change goals.

Metrics: (1) Percent of customer load from customers who own EVS, by customer sector, by month and by year, by circuit. (2) Preparation of an EV hosting map. (3) Number of independently-owned (by customer or third party) charging stations, by month and by year, by circuit. (4) Investment in make-ready work for EV charging stations. (5) Provision of and participation in customer awareness and education events.

Behind-the-Meter Storage

Description: To encourage the utility to promote cost-effective behind-the-meter storage in order to accelerate deployment of a new flexible resource.

Metrics: percent of customer load with storage, annual and cumulative, by customer class.

Target: TBD after sufficient metrics information is collected.

Incentive: TBD. Options include dollar per customer, dollar per kW of storage.

Utility-Scale Storage

Description: To encourage the utility to assess and implement storage technologies where cost-effective in order to accelerate deployment of a new flexible resource.

Metrics: (1) number of substations served by utility storage. (2) MW of utility storage installed.

Network Support Services

Access to Customer Info

Description: To encourage the utility to increase customer and third-party access to customer consumption information in order to improve market performance and customer decision-making. This will depend upon the implementation of Advanced Meter Functionalities.

Metrics: (1) Percent of customers able to access hourly or sub-hourly usage data, by customer sector, by year. (2) Percent of customers that provide hourly or sub-hourly usage data to third-parties, by customer sector, by year.

Targets. TBD. This should begin with current levels and reflect reasonable increases from those.

Incentive: TBD. This should be based on the targets developed.

- Aggregated Customer Data: The utility should make available a basic set of uniform aggregated customer datasets at no charge: monthly kW and/or ICAP, customer counts, and kWh data aggregated by zip code and/or tax district, and segmented by rate class. For rate classes with time-of-use periods, kW and kWh data should be aggregated by time-of-use periods and in total.
    - All aggregated customer datasets should be provided by a date certain.

- Future Datasets: The utility should engage DER providers to identify any additional customer-oriented datasets of value and propose a schedule for provision of new datasets over time. The utility should work with DER providers and regulators to define use cases[1] for future datasets and receive input on data formats and prioritization. The schedule should be informed by the utility's ability to collect and generate new datasets as enabled by proposed timetables for implementation of advanced grid connectivity and functionality.

Interconnection Support

Description: To encourage the utility to reduce time and cost of interconnection in order to better serve customers who want to generate or store electricity. This performance area is expected to be addressed in an upcoming Commission docket.

Metrics: (1) Average days for customer interconnection, by month, by customer sector. (2) Average cost of interconnection, annually, by customer sector. (3) Difference between initial estimate and actual cost of interconnection.

Target: TBD. This should be based upon reasonable improvements over past practices, depending upon the extent to which these practices have been a problem in the past.

Incentive: TBD. This should be based on the targets developed. Options include dollars per reduction in interconnection time; dollars per average cost of interconnection; dollars per reduction in actual costs.

Distribution System Planning

Description: To encourage the utility to use distribution system planning in order to provide network support and encourage the implementation of distributed energy resources that reflect system value.

Metrics: (1) Preparation of forecasts of utility, customer, and third-party distributed energy resources, by customer sector, by year, by circuit if feasible. (2) Preparation of forecasts of locations and magnitudes of independent EV charging stations.

Income Eligible Customers

Description: To encourage the utility to recruit eligible customers to participate in discounted rate plans.

Metric: the percent of census based population participating in the income eligible rate.

Target: TBD. Current participation rate is about 50 percent. California utilities have achieved 90 percent participation.

Customer Engagement

Description: To encourage the utility to increase customer engagement in distributed energy resources and network support services in order to enable customers to play their

part in the energy market, and motivate a support structure of aggregators and service providers to help.

Metrics: (1) Customer engagement surveys. (2) Transaction conversion rate at customer portals and platforms. (3) Customer participation rates in specific initiatives (e.g., energy efficiency, demand response program, distributed generation programs, AMF offerings, TVR offerings). (4) Customer education programs.

Beneficial Heating

Description: To encourage conversion of fuel oil customers to electric heat.

Metric: MW of electric heating capacity installed

Targets: TBD

In addition to these financial incentives, there are some performance incentives that are worthy of reporting only. These include:

Substation Capacity Factor

Description: To indicate the extent to which specific substations are stressed in order to signal attention from the utility, regulators and stakeholders.

Metric: For a select number of the most stressed substations, the ratio of capacity utilized during peak hour to the nominal capacity rating of the substation, by month and annually.

Target: None. One could be developed after assessment of historic capacity factors.

DG-Friendly Substations

Description: To indicate the portion of substations that are capable of readily installing distributed generation.

Metric: Ratio of substations that can accept DG without upgrades, to all substations.

Target: None. One could be developed after assessment of historic ratios.

Distribution Load Factor

Description: To indicate the efficiency with which the distribution system is being used, regarding the relationship between peak demand and energy consumption in order to assess the utilization of capital and its influence on unit delivery rates. In general, a higher load factor means that the system is being used more efficiently.

Metric: The ratio of retail sales during the peak hour to retail sales in all hours, by month and annually.

Target: None. While this is a useful metric to monitor, there are risks with assigning targets or incentives: load factor can be increased by simply increasing electricity sales; this metric is subject to other PIMs; and load factor can be influenced by factors outside utility control.

Customer Load Factor

Description: To indicate customer demand relative to energy consumption. In general, a higher load factor is more efficient is less costly to serve.

Metric: Ratio of distribution sales during peak hour to distribution sales in all hours, by month and annually, by customer sector. Requires interval metering.

Target: None. While this is a useful metric to monitor, there are risks with assigning targets or incentives: load factor can be increased by simply increasing electricity sales; this metric is subject to other PIMs; and load factor can be influenced by factors outside utility control.

Customer Intensity

Description: To indicate the amount of consumption by each customer class, and how that might change over time.

Metric: Ratio of sales to number of customers, by customer sector, annually.

Target: None. While this is a useful metric to monitor, there are risks with assigning targets or incentives: developing a baseline is challenging; this metric is affected by factors outside of utility control; and this metric is subject to other PIMs.

Recommendation 1.3 **Partnership Models for the Transition to an Information-Based Utility**

There are at least four areas in which the electric utility may seek to leverage the performance incentive mechanisms described here and, in combination with existing capabilities, develop new initiatives to advance intelligent infrastructure. We outline broad terms these areas and potential commercial arrangements to solicit stakeholder feedback and to allow market parties to innovate. Even beyond these individual areas for innovation partnership, utilities should be cognizant of how different technologies and partners connect with each other. The best partnerships will result in interoperable tools and platforms that empower each other.

Utilization of shared communications infrastructure:

A communications infrastructure is essential to many of the functionalities identified in the Grid Connectivity and Functionality work stream, including advanced meter infrastructure and time of use rates. To realize a shared communications network among various infrastructure providers we can envision three potential commercial arrangements:

- the use of public next generation connectivity for the electrical system in which the electric utility purchases a bulk amount of bandwidth and electricity ratepayers act as a kind of anchor tenant
- Ownership of a communications infrastructure by the electric utility with sales to other bulk infrastructure customers in which electric ratepayers fund the communications network and have costs reduced

- Participation by the utility in a special purpose vehicle with private vendors as a layer to support multiple infrastructure applications

Advanced Meters

National Grid has identified ownership of the meter as an important operational requirement for reliability. However, ownership and control are not barriers to allowing one or more third parties to operate the meter as a platform for data-based services. The license to operate such a platform could become a source of revenue for National Grid.

Electric vehicle charging stations

Electric vehicle charging stations represent an opportunity for the utility to earn revenue from a number of non-volumetric services, including:

- subscription fee services,
- installation services,
- charging station coverage maps stemming from distribution system services

Data Analytics

The distinction between "data" and "information" represents an important commercial opportunity for the utility and third parties to provide both public access to basic data and commercial access to information as the digested and improved product for market use. The emergent data and information portal could become a source of revenue for National Grid which could be used to offset other expenses for the benefit of ratepayers. Distributed energy resources developers would have access to some data without charge and might subscribe to have access to other information if they chose to find it of value.

1.4 Revise Service Quality Standards

At a minimum, cyber-security preparedness an customer engagement metrics shuld be expanded and enhanced.

1.5 Long-Term Consideration of a Total Expenditure Approach

The recommendations outlined here take significant steps towards aligning the regulated utility's economic incentives with the state's interests and policy goals. There are additional reforms that require further discussion and investigation. We recommend that state policymakers and the Company and other stakeholders undertake a sustained process to investigate a "total expenditure" approach to determining the utility's rate-base. The results of the investigation would be applied in the utility's next rate-case in 2020.

The proposed robust performance incentive mechanisms are designed to leverage the company's desire to maximize its overall return on equity to achieve state objectives that will benefit

ratepayers. However, even in the presence of these incentives, there will remain an inherent financial bias for the utility to apply capital expense solutions rather than operational expense solutions, because the utility's authorized return on equity applies to capital expenses, not operational expenses.

A Total Expenditure Approach combines the projected operating expenses and capital expenses and sets a percent of profit margin the utility can earn on the total amount, regardless of which type of expense. Under this system, a utility may decide to invest in maintenance rather than a more expensive capital replacement without facing a penalty of lost profit opportunity. .

Taken together, these considerations guide the definition of what the utility of the twenty-first century should do, how it should earn revenue, and what kind of metrics should shape its operation. They represent the first step on a multi-year process to change the incentive structure of the electric utility. That process will succeed only if the utilities and decision-makers maintain their determination to learn, adapt, and implement over the coming decade.