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

May 1, 2017

Following the Utility Business Model Technical Session held on April 24, 2017, stakeholders are invited to submit comments in response to the discussion and additional questions provided in this document to inform the ongoing inquiry into the utility business model. Comments should be submitted by **May 19, 2017**.

Introduction

Over the last decade, Rhode Island's power sector has begun to change. The signs of change include a greater number of electric customers who participate actively in energy production, the utility's increased capability to view and remotely control the electric system, the promise of new kinds of services to optimize the efficiency of the electric system, and the creation of topically focused performance incentive regulation. Together, these changes reflect a larger transformation of the power sector from a system organized around the flow of electricity from central station generators to end users toward a system with multi-directional power flow, greater flexibility, and higher system efficiency.

The Power Sector Transformation Initiative seeks to shape the ongoing transformation of the electric grid to achieve three policy objectives:

- **Control the long-term costs of the electric system**
  The regulatory framework should promote a broad range of resources to increase the ratio of average to peak electric load, helping to right-size the electric system to Rhode Islanders' needs.

- **Give customers more energy choices**
  The regulatory framework should allow customers to use emerging technologies and commercial arrangements to manage their energy production and use.

- **Build a flexible grid to integrate more clean energy generation**
  The regulatory framework should promote the flexibility needed to allow the electric grid to incorporate an increasing proportion of variable clean energy through use of demand response and energy storage, for example.

Reasons to Inquire into the Electric Utility Business Model

As the steward and architect of the electric distribution system, the electric utility occupies a central place in the changing power sector. The functions the utility performs, the way it determines its revenue requirement, and the incentives under which it operates create the *utility business model.* Understanding how existing financial incentives shape the electric utility's operations and ensuring that those incentives advance policy outcomes is an essential step for this inquiry. There are several considerations that may shape inquiry into the utility business model. These considerations include:

"Infrastructure Bias". The traditional regulatory model for electric utilities, in which the electric utility earns a return based largely on the cumulative value of the prudent infrastructure it has deployed, may exert an "infrastructure bias" to deploy capital-intensive solutions. As distributed energy resources and grid control technologies offer new opportunities to provide reliable service at low cost, the impact of this infrastructure bias on ratepayers will tend to grow. Topical incentives may correct this "infrastructure bias;" but as corrective incentives become more widespread a broader evaluation may be needed.

Historical Precedent. Rhode Island has previously recognized that cost of service regulation is not always, in itself, adequate to achieve state energy objectives. For example, the 2014 Renewable Energy Growth Program[1] , the 2009 Long Term Contracting Standard for Renewable Energy[2] and the 2016 System Reliability and Least-Cost Procurement [3] 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.

Risk of Technology Obsolescence. The electric system of the twenty-first century will be asked to deploy a range of new technology systems and to manage the risk of technology obsolescence, creating new challenges for the current business model in which capital expenditures are usually recovered directly based on a prudency test.

Data Connectivity. Similarly, 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. 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.

Taken together, these considerations may guide the inquiry into what the utility of the twenty-first century should do, how it should earn revenue, and what kind of metrics should shape its operation.

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:

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[1] R.I.G.L. § 39-26.6
[2] R.I.G.L. § 39-26.1
[3] R.I.G.L. § 39-1-27.7 e.

- 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?

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

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

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?

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?

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?

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

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

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?

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?

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

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?

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?

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?

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?

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?

Stakeholders are invited to submit their comments and any additional materials relevant to this inquiry into the utility business model. All comments will be made available to the public on the DPUC website. Please submit comments by Friday, May 19th by electronic mail to DPUC.powertransformation@dpuc.ri.gov

Thank you,