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April 25, 2018

Ms. Luly Massaro, Clerk
Rhode Island Public Utilities Commission
89 Jefferson Boulevard
Warwick, RI 02888

Re: Docket No. 4780 - The Narragansett Electric Co. D/B/A National Grid's Proposed Power Sector Transformation (PST) Vision And Implementation Plan

Dear Ms. Massaro:

Enclosed please find an original and nine copies of the following document:

1. Direct Testimony of Ronald J. Binz on behalf of the Northeast Clean Energy Council and the Conservation Law Foundation (Exhibit NECEC-CLF-2).

Please note that an electronic copy of this document has been provided to the service list.

Thank you for your attention to this matter.

Sincerely,

Joseph A. Keough, Jr.

JAK/kf
Enclosures
cc: Docket 4780 Service List *(via electronic mail)*

STATE OF RHODE ISLAND

IN RE: NATIONAL GRID APPLICATION TO CHANGE ELECTRIC AND GAS DISTRIBUTION REVENUE REQUIREMENTS AND ASSOCIATED RATES	DOCKET NO. 4780

TESTIMONY OF RONALD J. BINZ

ON BEHALF OF

NORTHEAST CLEAN ENERGY COUNCIL (NECEC)

AND

CONSERVATION LAW FOUNDATION (CLF)

Filed: April 25, 2018

Table of Contents

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND ADDRESS.

A. My name is Ronald J. Binz. My business address is 333 Eudora Street, Denver, Colorado 80220.

Q. ON WHOSE BEHALF ARE YOU SUBMITTING TESTIMONY?

A. I am submitting testimony on behalf of the Northeast Clean Energy Council (NECEC) and Conservation Law Foundation.

NECEC is a clean energy business, policy and innovation organization. Its mission is to create a world-class clean energy hub in the Northeast delivering global impact with economic, energy and environmental solutions. NECEC is the only organization in the Northeast that covers all the clean energy market segments, representing the business perspectives of investors and clean energy companies across every stage of development. Its members span the broad spectrum of the clean energy industry, including energy efficiency, demand response, wind, solar, combined heat and power, energy storage, fuel cells, and advanced and “smart” technologies. Many of its members are doing business and investing in Rhode Island, and many are interested in doing so in the future.

Conservation Law Foundation (CLF) is New England’s leading environmental advocacy organization. Since 1966, CLF has worked to protect New England’s people, natural resources and communities. CLF is a nonprofit, member-supported organization with offices throughout New England. The Rhode Island CLF office is located at 235 Promenade Street, Suite 560, Providence, RI 02908. Thanks to CLF's effective advocacy – in courtrooms, in statehouses, and in boardrooms – today Boston Harbor is the pride of the city, Georges Bank is free from oil and gas rigs, Lake Champlain's polluted waters are getting cleaner, and New England's remaining obsolete coal plants are on the verge of shutting down for good. As part of a 50-year legacy, CLF was a party in the landmark case in which the U.S. Supreme Court ruled that the U.S. Environmental Protection Agency has an obligation under the Clean Air Act to consider regulating tailpipe emissions that contribute to global warming, Massachusetts v. E.P.A., 127 S. Ct. 1438 (2007).

Q. WHAT IS YOUR OCCUPATION?

A. I am a consulting regulatory policy analyst, specializing in energy and telecommunications issues. My practice is called Public Policy Consulting.

Q. PLEASE DESCRIBE YOUR EXPERIENCE AND QUALIFICATIONS.

A. For more than forty years I have served in a variety of roles as an expert in energy policy and regulation, including as a regulator, consumer advocate, expert witness, an advisor, researcher and consultant. From 2007 to 2011, I was the Chairman of the Colorado Public Utilities Commission ("PUC"). During this period, energy policy, led by the Governor and Legislature, moved forward toward the "New Energy Economy" in Colorado, expanding the use of clean energy resources, and ramping up the energy efficiency actions of the regulated electric and gas utilities.

In June 2013, I was nominated by President Obama to become the Chairman of the Federal Energy Regulatory Commission ("FERC"). After a confirmation hearing before a U.S. Senate Committee, I requested that the President withdraw my name from further consideration due to the opposition of the coal industry and certain conservative political groups.

Since 1977, I have participated in more than 150 regulatory proceedings before FERC, the Federal Communications Commission ("FCC"), state and federal district courts, the Eighth Circuit Court of Appeals, the Tenth Circuit Court of Appeals, the D.C. Circuit Courts of Appeal, the U.S. Supreme Court, and state regulatory commissions in California, Colorado, Georgia, Hawaii, Idaho, Maine, Massachusetts, Missouri, New York, North Dakota, South Dakota, Texas, Utah, Wyoming and the District of Columbia.

Prior to my service on the Colorado PUC, from 1984 to 1995, I was the Consumer Counsel for Colorado, representing the interests of residential, small business and agricultural utility consumers before the Colorado PUC, federal regulatory agencies, and the courts.

My *curriculum vitae* is attached as Attachment A.

II. PURPOSE OF THE TESTIMONY AND SUMMARY OF RECOMMENDATIONS

Q. WHAT IS YOUR ASSIGNMENT IN THIS CASE?

A. I was retained by Vote Solar to provide my expert opinion for NECEC and CLF on certain regulatory proposals made in this case by Narragansett Electric

Company d/b/a National Grid ("National Grid" or "Company") before the Rhode Island Public Utilities Commission ("PUC" or "Commission"). Specifically, I was asked to examine the Company's proposed Performance Incentive Mechanisms (PIMs) and the surrounding regulatory approach advocated by National Grid for its proposed investments in the Power Sector Transformation (PST).

Q. WHAT IS THE INTEREST OF NECEC AND CLF IN HOW THESE REGULATORY ISSUES ARE DECIDED?

A. NECEC and CLF believe that Rhode Island must move toward a revised regulatory regime that will align the incentives provided to National Grid with customer and public policy objectives. Regulation should enable the Company to transform itself into a utility that can thrive in a world of advancing technology, increasing deployment of distributed energy resources and changing customer expectations. This is consistent with the recommendations of the Power Sector Transformation Phase One Report ("PST Report). [1] In sum, regulation should create a marketplace for products and services that can be provided by clean energy companies, utilities and partnerships between them.

Given the preparation of the PST Report and the Commission's decision in Docket No. 4600, the time is ripe for the entire energy community in Rhode

[1]"Rhode Island Power Sector Transformation, Phase One Report to Governor Gina M. Raimondo". November 2017.

Island – regulators, utilities, clean energy companies and consumers – to move forward on implementing a shared vision of the power sector in this state.

Any major filing of an electric utility is an opportunity to refine and realize policy direction: the instant case is an especially propitious opportunity. NECEC and CLF wish to assist the Commission in moving forward on Rhode Island's power sector transformation.

Q. PLEASE SUMMARIZE YOUR FINDINGS AND RECOMMENDATIONS CONCERNING NATIONAL GRID'S PROPOSALS.

A. In summary, I find and recommend the following:

- Achieving the full vision announced in the PST Report will require fundamental changes to the way the Commission regulates electric utilities. Rate base rate-of-return regulation, as currently practiced, needs to evolve to a regulatory system that offers National Grid desirable incentives to achieve agreed goals and provides the flexibility for the Company to transform itself to meet the challenges of an evolving electric power sector.
- It is important that the Commission use the opportunity of this case to begin the reform of regulation for National Grid. The Commission should establish a process that will lead to the goal of performance-based "revenue-cap" regulation for National Grid.
- The proposal of National Grid to incorporate performance measures into its regulation is a modest step in the right direction. Most of the Performance Incentive Mechanisms (PIMs) proposed by National Grid will be helpful, but their

application can be improved. More important, the PIMs should be incorporated into a more fundamental reform of regulation, such as a revenue-cap regime or a multiyear plan framework as recommended and outlined by the Division of Public Utilities and Carriers ("DPUC") in its testimony in Docket No. 4770.[2]

- My testimony contains specific recommendations about the structure of some of the proposed PIMs, including the level of reward associated with performance on each PIM.
- The Commission should not create a new "cost tracker" for PST-related costs. If a multi-year rate plan is adopted, these costs will be included in the multi-year revenue cap trajectory. If the Commission allows National Grid to proceed with a one-year rate plan, the Company should be required to file rate cases to reflect increased PST-related costs.
- Finally, I recommend certain *procedural* steps the Commission should employ to accelerate the move toward a more appropriate regulatory structure. The Commission should either 1) require National Grid to negotiate a multi-year rate plan in this case or 2) grant only interim rate relief, during which period the parties are directed to negotiate a comprehensive revenue cap or multi-year rate plan consistent with Commission directives.

[2] See Attachment B, Direct Testimony of Tim Woolf On Behalf of The Division of Public Utilities and Carriers, Rhode Island Public Utilities Commission Docket No. 4770.

III. PERFORMANCE-BASED REGULATION GENERALLY

Q. WHAT IS INCENTIVE REGULATION?

A. In common use, "incentive regulation" usually means a regulatory scheme that incorporates explicit incentives to induce utilities to undertake certain behavior. It is usually contrasted with "traditional" utility regulation. But this common use can be incomplete and misleading.

I agree with the opinion, first expressed by Commissioner Peter Bradford, the former utility regulator in Maine and New York, that "all regulation is incentive regulation." By this he meant that any method of regulation provides incentives (some explicit, some not) that affect the behavior of utilities. There is no "neutral" or "incentive-free" style of regulation.

To see that even "traditional" regulation is a type of incentive regulation, consider two examples. Under traditional rate base, rate-of-return regulation, a utility's operating income (profit) is determined as the product of rate base investment and the utility's cost of capital. This use of investment to determine profit can produce the well-known "Averch-Johnson Effect" in which utilities invest "too much" capital, compared to its investment in labor. The reasoning here is straightforward: when earnings are tied to return on rate base and expenses are compensated "at cost", it is more profitable for the utility to address a challenge (e.g., reliability) with more capital investment, compared with more employees, distributed generation, or demand response.

Second, under the traditional regulatory bargain, utilities had an incentive – called "regulatory lag" – to become more efficient. If a utility had to wait until its next rate case to raise prices, there was a short-term incentive to "tighten its belt" to keep earnings at desired levels. This incentive has largely disappeared as utilities have succeeded in winning regulatory approval of numerous "adjustment clauses" that pass cost increases through in customer rates as the cost increases are experienced.[3] Today many utilities approach regulation as simply an exercise in dollar-for-dollar "cost recovery" as expeditiously as possible.

With this background, we see that the task of regulation today is not to decide *whether* to offer incentives, but instead to determine *which* incentives to offer. Sometimes regulatory reform can mean replacing one incentive with another incentive. In particular, there are ways to modify regulation to blunt utilities' "capital bias," to restore incentives toward efficiency, and to add incentives for innovation.

Q. WHAT IS MEANT BY "PERFORMANCE-BASED REGULATION?"

A. For many years, U.S. electric utility rate making has been based on the traditional implementation "rate-of-return, cost-of-service" methodology. In this scheme, a utility's rates are set to collect the cost of providing service, which is estimated to

[3] Over the past two decades, utilities have campaigned against "regulatory lag," mischaracterizing its purpose and effect. To be clear, the debate is not about the speed with which regulators make decisions: regulators should always act expeditiously on matters brought to them. It is a separate question entirely whether regulation should be configured to instantly pass through increases in costs incurred by utilities without the lag inherent in filing a rate case in which the entire financial picture is examined. Regulatory lag mimics the effects of a competitive market place in which competing companies are not free unilaterally to pass on cost increases as they occur.

be expenses plus depreciation plus taxes plus a return on the regulated rate base. Typically, a utility's performance played no direct or integrated role in rate-setting. Regulators would enforce standards of service quality and customer satisfaction on a separate track, sometimes levying penalties for inadequate performance and, occasionally, bonuses for exceptional performance.

This traditional regulatory scheme is now being reassessed to consider systems in which revenues are based, partially and directly, on the utility's performance on a set of desired outcomes. These outcomes include the familiar measures of reliability, safety and customer satisfaction, but also new desired outcomes such as environmental performance, energy efficiency program delivery, customer engagement, quality of interconnection service, carbon reduction, etc. The longer list of performance categories reflects the new complexity and changing nature of the utility business.

These various new regulatory schemes are grouped under the term "performance-based regulation" or "PBR." The PBR schemes can vary from simply grafting a few performance measures onto a standard cost-of-service model, to more complex systems such as the UK regulator has adopted. Importantly, PBR can be used in conjunction with cost-of-service regulation or with other systems of determining fair compensation, such as "revenue-cap" regulation, which I will discuss later.

Q. WHAT IS YOUR VIEW OF PERFORMANCE-BASED REGULATION?

A. I support the nascent move in the United States toward performance-based regulation in the power sector. The electric power sector has obviously changed significantly in recent years with new technologies, DERs, increased environmental demands and the promise of more choices for customers. Each of these developments challenges the prevailing utility business model and has set utilities on a course to invent a new business model.

For multiple reasons, traditional cost of service regulation no longer provides clear incentives to the regulated utilities that are well aligned with customer interests. At the same time, advances in regulation, some of which originated in the telecommunication industry, now offer improved incentives and provide utilities more flexibility to reshape their business models in response to the significant changes in the electric power sector. As a former regulator, I am convinced that the move toward performance-based regulation is in the best interests of consumers.

Q. WHAT INFORMS YOUR GENERAL SUPPORT FOR PERFORMANCE-BASED REGULATION?

A. Since leaving the Colorado PUC in 2011, much of my work has focused on the related topics of "the new utility business model" and "a new regulatory model" that can enable utilities to respond successfully to the technological and structural changes in the sector. These structural changes include the increased prevalence and cost effectiveness of DERs, the need to reduce carbon emissions and the need to mitigate upward rate pressure due to replacement of aging grid infrastructure in the upcoming decades.

As part of that work, I led a 15-month project, ***Utilities 2020***, which brought together regulators and industry leaders to develop and promote thinking about these topics. The findings of the ***Utilities 2020*** project support the implementation of properly designed performance-based regulation in place of traditional cost-of-service regulation.[4]

Q. PLEASE DESCRIBE THE UTILITIES 2020 PROJECT.

A. ***Utilities 2020*** was a "research and action project" established to explore the connected issues of evolving utility business models and changes to state utility regulation needed to enable them. One of the main research tools employed by ***Utilities 2020*** was interviews of utility CEOs and leading state regulators, along with numerous other leading thinkers in the field. In addition, ***Utilities 2020*** hosted a dialogue in October 2012 with twelve state regulators from across the country, senior executives from eight utilities, as well as consumer advocates and other experts in energy and regulation. Finally, in December 2012, ***Utilities 2020*** principals hosted a meeting in Boston of seven established and seasoned leaders in energy policy and regulation to discuss the potential new utility business/regulatory models.

[4] "Utilities 2020 Report: Key Findings." Available at: www.rbinz.com/U2020PublicReport.pdf

Q. WOULD YOU HIGHLIGHT SOME OF THE FINDINGS OF *UTILITIES 2020*?

A. In general, the ***Utilities 2020*** findings highlighted the need for reform that creates certainty and improves the business-as-usual regulatory processes for both utilities and regulators. Among other topics, nearly all the CEOs we interviewed believed that, under current practice, regulation does not provide utilities with meaningful incentives to improve internal efficiencies. We heard that "if we save a buck, they take it away from us in the next rate case," and that "our best outcome is that we recover the cost of a measure; there's no upside." They agreed that higher firm efficiencies are possible and that these could function somewhat to offset the higher costs expected over the next two decades. Most regulators we spoke with expressed a primary concern that the challenges facing utilities, particularly the coming high level of new investment, will translate into higher customer rates.

Q. WHAT WERE THE RECOMMENDATIONS OF THE UTILITIES 2020 PROJECT?

A. The primary finding was that reform of the utility business model depended on changes in the regulatory model. The project identified three potential models of regulation that could be adapted for use in state regulation. One of the potential regulatory models highlighted in ***Utilities 2020*** was "revenue cap" regulation. An instance of this type of regulation is the mechanism used in the United Kingdom called "RIIO," which stands for "Revenue set to deliver strong Incentives, Innovation and Outputs."[5] The other two main models discussed by Utilities 2020 were the "Iowa Model," and the "Grand Bargain."

Q. CAN YOU DESCRIBE THE RIIO REGULATORY MODEL?

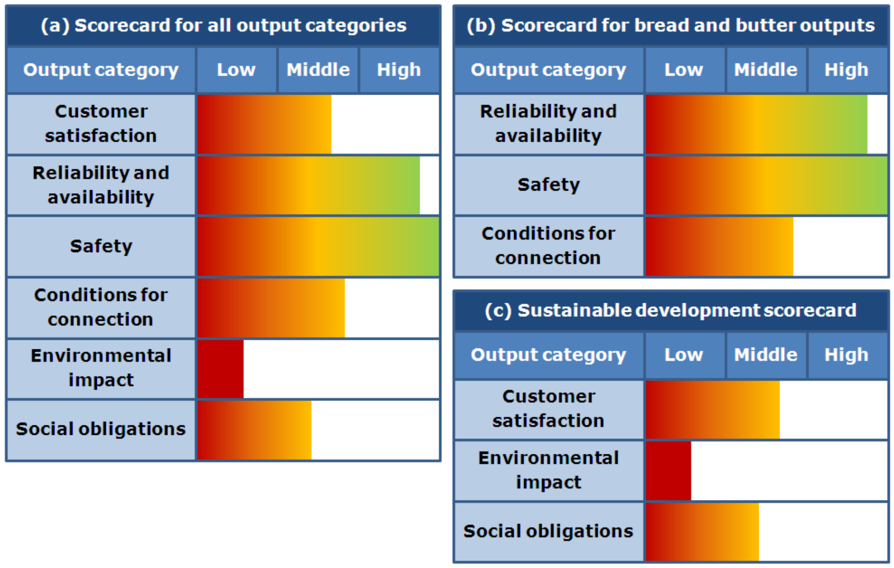
A. In the UK, RIIO builds on the price cap regime used for the past 20 years for energy companies (called "Retail Price Index minus X," or "RPI-X"), adding a system of rewards and penalties tied to performance on desired outcomes (or "outputs") to be achieved by regulated companies. By its own terms, this UK model seeks "value for money."[6] New rewards and penalties provide an incentive system to encourage operational efficiencies, funding for innovation and opportunities for utilities to involve third parties in energy delivery. RIIO also decouples earnings from sales.

Under RIIO, utilities are graded for their following performance on six output measures:

- Customer satisfaction,
- Reliability and availability,
- Safe network services,
- Connection terms,
- Environmental impact, and
- Social obligations.

[5] There are other variations on the meaning of the acronym.
[6] "Handbook for implementing the RIIO model", Office of Gas and Electric Markets (Ofgem), 2010. London. P. 1. Available at www.ofgem.gov.uk.

RIIO rewards or penalizes utilities' performance on these output measures based on a "report card," illustrated in the following graphic:[7]



Q; PLEASE EXPLAIN THE "IOWA MODEL" AND THE "GRAND BARGAIN" REGULATORY MODEL.

A. In our ***Utilities 2020*** research, we became aware that Mid-American Energy in Iowa had gone for almost 20 years without filing a rate case. Instead, the Company had been regulated by a series of negotiated rate settlements among the utility, the state consumer advocate and the Commission staff. The terms of the negotiated settlements averaged about four years in length. During this time, Mid-American added large amounts of investment in wind energy and speeded up depreciation of many of its older assets.

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[7] Id, p. 81.

From all reports, the state of Iowa achieved many of its goals – improved service quality, rate stability and reduced carbon emissions – through this unusual collaborative ratemaking regime. The utility reported that the multi-year character of the rate settlements allowed it to make rational investment decisions benefitting the company, independent power producers and consumers. The practice in Iowa stood out as an innovative way of aligning interests – utility, consumer, environmental, business – while providing a clearer set of economic incentives to the utility.[8]

"The Grand Bargain" is not so much a model for economic regulation as a process for developing an improved regulatory outcome. In this scheme, the regulator would dispatch a collaborative process to negotiate a multi-year set of prices and desired outcomes. The regulator would accept or reject the negotiated result. At the front end, the regulator would provide boundaries that (preliminarily) determined what outcomes would be acceptable.

The negotiating parties would not be bound to any particular method for arriving at a multi-year schedule of rates: the Grand Bargain could be opaque with respect to how the rates were determined and what tradeoffs were involved in the settlement. Finally, the parties in the collaborative process would understand that the Commission was predisposed to accept a settlement agreed to by all parties;

[8] "Utilities 2020 Report: Key Findings." Available at: www.rbinz.com/U2020PublicReport.pdf

however, the Commission would be prepared to enter a decision if consensus was not reached.

Q. HOW MIGHT THE UK'S EXPERIENCE WITH RIIO AND THE ELEMENTS OF THE OTHER MODELS APPLY IN RHODE ISLAND?

A. There are many opinions about RIIO, but most observers agree that RIIO has succeeded in shifting the focus of UK regulation toward "outcome-based" regulation, while inducing greater efficiency and innovation in the regulated companies. I agree with many observers that the entire RIIO package may be too unwieldy to apply in all its details in the U.S. That said, RIIO is a good example of the *features* that might advisedly accompany a new regulatory model for U.S. electricity regulation. In our research, we concluded that features such as revenue-cap regulation, decoupling and measuring "outputs" could be applied in U.S. regulation with salutary effect.

The experience in Iowa is instructive because it shows that standard US utility regulation can be modified in a straightforward manner to dampen the undesirable effects discussed earlier. Mid-American Energy showed how a long-term regulatory agreement could fundamentally affect its investment behavior. Finally, the Grand Bargain points the way to how commissions can procedurally set in motion a fundamental change in regulatory results. As discussed below, all three models could have a place in the Commission's decision in the National Grid application in this case.

A. Elements of an Effective PBR Regime

Q. BASED ON YOUR RESEARCH AND EXPERIENCE, WHAT ARE THE ELEMENTS OF AN EFFECTIVE PBR REGIME?

A. Based on the work I did for ***Utilities 2020*** and reflecting on the RIIO model, I suggest that a successful PBR regime should have the following five features:

1. Growth in allowed base revenues is tied to an external measure, and not related directly to investment choices;
2. Utility performance meaningfully affects allowed revenues (up and down);
3. The mechanism is in place for a period that is sufficiently long to allow the utility time to prove out the economics of its investment and expense decisions;
4. The link between total sales and earnings is decoupled; and
5. The ratemaking regime ties utility revenues to the achievement of certain outcomes or "outputs."

Finally, it is also critical that the new regulatory system be seen to be fair so that it can be sustained for an extended period. The persistence of a PBR regime is essential for the utility to be able to make long-term changes in its behavior.

Q. PLEASE SUMMARIZE YOUR OPINION ABOUT THE STRUCTURE OF A REGULATORY REGIME THAT SHOULD BE THE GOAL OF RHODE ISLAND POLICY MAKERS.

A. Putting together the parts discussed above, I recommend that Rhode Island's regulation of the electric power sector move toward ***Performance-Based Regulation based on Revenue-Cap Model.***

Q. AT A THEORETIC LEVEL, ARE THERE ANY DOWNSIDES TO USING REVENUE-CAP REGULATION?

A. When a utility is under a longer-term regime, it can increase earnings by spending less. It is literally true that "a penny saved is a penny earned." The most frequently voiced concern about revenue-cap regulation is the possibility that a utility will under-invest in safety and the reliability of the grid. An inducement to efficiency is desirable if the utility also maintains the quality of electricity delivery, especially its safety and reliability.

The prescription for avoiding this undesired outcome is two-part: 1) an incentive structure that counters such unintended consequences, and 2) dedicated enforcement of safety and quality standards.

Q. HOW DOES A PROPERLY DESIGNED PBR LIMIT THE "CAPITAL BIAS" THAT CAN ACCOMPANY COST OF SERVICE REGULATION?

A. Because traditional regulation measures utility rate base to determine allowed revenues and earnings, there is an inherent bias towards capital intensive solutions to grid issues. Stated another way, utilities do not earn a "return" on expenses in the same way they do with rate base capital investment. This bias is not alleviated by adopting revenue decoupling, and it is not mitigated by the addition of PIMs to traditional rate base, rate of return regulation. Putting "expense-like" solutions on an equal footing with "capital-like" solutions requires a fundamental change in the way utilities are compensated.

A PBR regime using the "revenue-cap" compensation model addresses this bias by paying a utility for the delivery of an outcome without reference to whether the outcome was achieved by any particular mix of capital and expenses. As a result, a PBR regime using a revenue cap compensation structure will focus on total expenses – "totex" – instead of capital expenses (capex) and operating expenses (opex) separately. This puts lower-cost "non-wires alternatives" on more nearly the same footing as utility capital investment. By selecting the lower-cost solution instead of the capital-intensive solution, a utility regulated under a revenue cap will increase earnings.

Q. IN DOCKET NO. 4770, THE DIVISION ADVOCATES THE USE OF A MULTI-YEAR RATE PLAN AS A PREFERRED APPROACH TO REGULATING NATIONAL GRID. WHAT IS YOUR RESPONSE TO THE DIVISION'S APPROACH?

A. Depending on its details, the effects of a multi-year rate plan can be similar to the "revenue-cap" approach discussed above. At a minimum, adopting a multi-year rate plan would represent progress toward the ultimate goal of an appropriate regulatory regime. Comparing such a plan to the characteristics I listed above, we see that those criteria could be met: a multi-year plan is, by definition, in effect for an extended period of time; it can tie earnings significantly to performance; year-to-year changes in maximum allowed revenues are set without reference to actual expense or investment levels, typically in a negotiation; revenues are decoupled from sales; finally, there is a focus on outcomes of the utility's efforts during the control period, not on the choices of capex or opex.

In sum, a multi-year rate plan could combine elements of the three models discussed previously: the outcome focus and revenue control of RIIO-style regulation; the multi-year characteristic of the "Iowa model;" and the use, at the front end, of a broad negotiation of the outcomes and revenue levels.

A multi-year rate plan will be less successful if it applies for a relatively short period; if it clings to rate base in setting the annual price changes; or if it omits or minimizes the revenue importance of performance measures.

IV. THE NATIONAL GRID PROPOSAL

Q. PLEASE DESCRIBE NATIONAL GRID'S PBR PROPOSAL IN THIS CASE.

A. National Grid is proposing a two-faceted incentive regulation proposal. First, the Company proposes mechanisms designed to improve the Company's management of capital investment projects in its Infrastructure, Safety and Reliability ("ISR") Plan and in its expansion of the distribution grid. Second, the Company proposes eight specific "Performance Incentive Mechanisms" or "PIMs" that address performance in three general areas: (1) system efficiency; (2) DERs; and (3) network support services.

Importantly, National Grid is not proposing any far-reaching changes to its regulation, even though it acknowledges in testimony the central role that PBR will play in the state's Power Sector Transformation:

> *A shift toward performance-based regulation is foundational to the power sector transformation envisioned by the state. This chapter proposes first steps in what is likely to be a longer process of*

> *evolution that uncovers new opportunities to incent both overall efficiencies and system cost reductions, while also driving exceptional utility performance in areas of importance. By rewarding utilities based on performance, regulation can better mirror the outcomes of competitive markets, where firms earn higher returns if they innovate and provide products and services that create more value for customers.* (Emphasis supplied.)[9]

In addition, the Company's rate filing in Docket No. 4770 is a traditional cost-of-service rate case, even though the Company acknowledges in testimony:

> *Although today's regulatory framework supports cost-recovery and earnings on investment deemed prudent by regulators, it is not sufficient to drive innovative utility performance in delivering these new objectives. To best encourage utilities to innovate and to align their financial interests with broader policy goals and customer outcomes that expand beyond core performance obligations, <u>new compensation mechanisms are needed</u>.* (Emphasis supplied.)[10]

The relatively conservative proposal by National Grid in Docket No. 4780 "toward performance-based regulation" represents a missed opportunity: National Grid's timid PBR proposal, limited to adding PIMs to traditional regulation, would be in place until 2022. Further reforms would have to wait until then. Similarly, the traditional rate case filed in Docket No. 4770 makes no progress toward a "new compensation mechanism[s]." It is up to the other parties to offer options and up to the Commission to move forward on regulatory reform.

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[9] RIPUC Docket No. 4770. Testimony and Schedules of Power Sector Transformation Panel. Book 1 of 3. November 27, 2017. Bates page 162.
[10] RIPUC Docket No. 4780. Testimony of Power Sector Transformation Panel. January 12, 2018. Page 83 of 102.

Q. WHAT IS YOUR OVERALL ASSESSMENT OF THE COMPANY'S INCENTIVE PROPOSAL RELATED TO CAPITAL INVESTMENT?

A. I am unconvinced that the "Complex Capital Projects Capital Cost Incentive" is necessary or even helpful. The incentive applies only to "major projects" and doesn't address the baseline capital investments made in the grid. Because it is structured as a one-way adder to the return on rate base, it likely reinforces the capital bias of any utility regulated this way. Finally, this structure exposes National Grid only to an "opportunity cost" of a foregone bonus of up to $2.5 million; the down-side risk is zero.

The "Construction Costs per Mile Productivity Incentive" has not yet been fleshed out by the Company. However, its purpose is to offer National Grid an opportunity for extra earnings when it can reduce the per-mile cost of distribution plant. Again, this mechanism appears to reinforce a commitment to capital construction of distribution facilities and does not incentivize the Company to explore non-wires opportunities. Not only will the Company add to rate base with distribution investment, it might earn a bonus for doing so. At the same time, non-wires alternatives do not add to rate base and do not present an opportunity for extra earnings.

In sum, true regulatory reform in Rhode Island must tackle issues around capital investment in a much more fundamental way. In my opinion, the approach to capital cost recovery proposed by National Grid might actually slow a move toward a more appropriate regulatory structure.

Q. WHAT IS YOUR OVERALL ASSESSMENT OF THE COMPANY'S PROPOSAL TO ADD PIMS TO ITS REGULATION?

A. The PIMs will probably be helpful, but they are quite small and unlikely to have a major effect. Even if the Company scores the maximum on all the PIMs, this structure would add only 75 basis points to the Company's ROE. There is very little at risk (only opportunity costs since the PIMs are positive-only) to the Company for poor performance on the PIMs. As a result, these PIMs cannot possibly be expected to engender transformational change within the utility.

A. Capital Cost Incentives

Q. PLEASE ELABORATE ON YOUR COMMENTS ABOUT THE CAPITAL COST INCENTIVES.

A. As discussed at length above, traditional regulation provides a complex set of incentives, some of which will hinder the transformation of the power sector. These counterproductive incentives must be eliminated through regulatory reform. The PST Report does a good job of describing the biases provided by cost of service regulation based on rate base. Four of the Report's recommendations provide a roadmap for the needed changes.

1.1 Create a multi-year rate plan and budget with a revenue cap to incent cost savings. The utility should submit a multi-year rate plan with a revenue cap that incents cost saving and shares those savings with ratepayers. This will better align the utility's financial incentives with economic efficiency and sound investments in capital and non-capital expenditures, and ultimately pass reduced costs on to customers
.

> *1.2 Shift to a pay for performance model by developing performance incentive mechanisms for system efficiency, distributed energy resources, and customer and network support. The utility's earnings growth will shift away from being based on the amount of capital it invests and towards a reflection of its performance. Incentives will encourage prudent investments in system efficiency, increasing distributed energy resources, network support services, and customer engagement.*
>
> *1.5 Assess the existing split-treatment of capital and operating expenses. The Division should convene a collaborative of stakeholders to consider opportunities for a total expenditure approach for future implementation to remove capital bias of the regulatory framework that currently drives cost increases.*
>
> *4.2 Establish outcome-based metrics. Beneficial electrification proposals should include tracking of outcome-based metrics that are relevant to consumers and public policy objectives.*[11]

The terms "revenue cap" and "capital bias" used in the Report's recommendations point to the fundamental changes needed to move National Grid's regulation to the place it needs to be. By proposing these two capital investment incentives, National Grid is making no progress towards the Report's recommendations.

If, instead, National Grid were regulated under a revenue cap for an extended period of time, all of the Company's capital investment would be under the ultimate incentive to be efficient. As explained earlier, revenue cap regulation will create genuine competition between capital and non-capital solutions.

[11] "Rhode Island Power Sector Transformation, Phase One Report to Governor Gina M. Raimondo". November 2017. 10-12. http://www.ripuc.org/utilityinfo/electric/PST%20Report_Nov_8.pdf

Further, the Company will have an incentive to be efficient in deploying capital investment: doing so will improve earnings in the short run and there will be no upside to inflating rate base with higher than needed capital costs.

Q. IS NATIONAL GRID FAMILIAR WITH REVENUE-CAP REGULATION?

A. Yes. National Grid is a transmission provider in the UK. All "wires" companies, -- both distribution and transmission companies – are regulated under the RIIO regime.

Q. ARE THERE ANY EXAMPLES OF "REVENUE CAP" REGULATION USED IN THE NORTHEAST?

A. Price-cap regulation was used extensively in telecommunications regulation in the Northeast beginning in the late 1980s. Notably, Vermont and New York were national leaders in moving away from cost-based regulation and toward price-based regulation. The "regulatory bargain" in those years began to evolve towards a focus on the desired outputs (quality, technological innovation, and interconnection parity) with much less emphasis on cost inputs.

The first steps toward revenue-cap regulation for electricity and natural gas in the Northeast included "decoupling" revenues from unit sales, adopted by many states. In recent years, there has been a move toward multi-year rate plans, which, as discussed above, can be a close relative to "revenue-cap" regulation. Most recently, the Massachusetts DPU approved a revenue-cap plan for Eversource in 2017. The plan allows annual revenue changes based on an external index, not on the costs or investment levels of Eversource. The annual revenues are "capped" by a factor of CPI-X, where CPI is the Consumer Price Index and X is the so-called productivity offset.

Q. DO YOU SUPPORT THE MASSACHUSETTS DPU'S DECISION?

A. While I strongly support PBR frameworks based on revenues caps, I do not support the MA DPU decision. As I testified in that case, the Eversource proposal relies on an incorrect X-factor that will produce revenues that are significantly too high. This will over-compensate Eversource and might create consumer or legislative resistance to revenue-cap regulation, giving incentive regulation a "bad name." Further, the Eversource proposal did not include performance incentive measures and lacked the focus on "outputs" that a proper PBR regime should contain.

Q. WHAT LESSONS SHOULD RHODE ISLAND REGULATORS TAKE FROM THE MASSACHUSETTS DPU'S DECISION?

A. While the outcome of the Eversource case in Massachusetts is disappointing, the PUC should move forward toward a beneficial change in electricity regulation in Rhode Island. The Commission can achieve a superior result by combining the benefits of revenue-cap regulation with a traditional focus on customer protection. Performance-based regulation, employing a revenue-cap approach, implemented correctly will result in superior outcomes for both customers and utility providers. There is no reason that incentive regulation should result in prices that are not fair. The PUC should ensure that, as it moves forward toward PBR, it advances customer interests at the same rate as utility benefits.

B. Performance Incentive Mechanisms (PIMs)

Q. PLEASE ELABORATE ON YOUR COMMENTS ABOUT THE COMPANY'S PROPOSAL FOR PERFORMANCE INCENTIVE MECHANISMS (PIMS).

A. National Grid has proposed a system of potential "earnings opportunities" associated with the Company's performance on a set of Performance Incentive Mechanisms (PIMs). These are expressed as potential basis point adders to the Company's allowed Return on Equity (ROE). As shown in the chart below, the maximum potential earnings opportunities are stratified by each category of performance and vary by year. In addition, and not shown in this table, there are three levels of achievement – Minimum, Target, and Maximum – for each

Table 9-1: Overview of Proposed Performance Incentive Mechanisms and Maximum Earnings Opportunity in Basis Points

Category and Supporting Metrics	2019	2020	2021
System Efficiency	**23.5**	**23.5**	**23.5**
Monthly Transmission Peak Demand Reduction	3	3	3
Forward Capacity Market Peak Demand Reduction	18	18	18
EV Off-Peak Charging Rebate Participation	2.5	2.5	2.5
Distributed Energy Resources	**29.5**	**29.5**	**29.5**
DG-Friendly Substation Transformers	10	10	10
DR -- Connected Solutions Participation	5	5	5
DR -- C&I Participation	5	5	5
Electric Heat Initiative	2	2	2
Electric Vehicles	3.5	3.5	3.5
Behind-the-Meter Storage	2	2	2
Utility-Owned Storage	2	2	2
Network Support Services	**22**	**22**	**22**
VVO Pilot Impacts	2	2	2
AMF Customer Engagement and Deployment	2	2	2
Interconnection -- Time to ISA	6	6	6
Interconnection -- Avg days to system modification	6	6	6
Interconnection -- Estimated vs actual costs	6	6	6
Total	**75**	**75**	**75**

performance category. In each annual determination, the Company's performance on each PIM is rated, and the appropriate ROE adder is calculated.

Q. WHAT ARE YOUR OBSERVATIONS ABOUT THIS PROPOSAL?

A. Without reference to any of the specific PIMs, I would first note that the potential maximum rewards for performance are very small. A change of 1 basis point on ROE equates to approximately $37,400 in operating income. This means that, if the Company performed at the Maximum level in all categories, after-tax earnings would increase by only about $2.8 million. At lower levels of performance, the potential rewards are even smaller. The following table shows the full detail from

"Revenue Opportunities" Associated with Performance on PIMs
Stated as Basis Points on ROE

Category and Supporting Metrics	Min	Target	Max
System Efficiency	9.0	16.3	23.5
Monthly Transmission Peak Demand Reduction	1.0	1.8	2.5
Forward Capacity Market Peak Demand Reduction	6.0	12.0	18.0
EV Off-Peak Charging Rebate Participation	2.0	2.5	3.0
Distributed Energy Resources	**5.3**	**16.8**	**29.5**
DG-Friendly Substation Transformers	1.0	6.0	10.0
DR--Connected Solutions Participation	1.0	3.0	5.0
DR--C&I Participation	1.0	3.0	5.0
Electric Heat Initiative	0.7	0.8	2.0
Electric Vehicles	1.0	2.0	3.5
Behind-the-Meter Storage	0.3	1.0	2.0
Utility-Owned Storage	0.3	1.0	2.0
Network Support Services	10.0	16.0	22.0
VVO Pilot Impacts	2.0	2.0	2.0
AMF Customer Engagement and Deployment	2.0	2.0	2.0
Interconnection--Time to ISA	2.0	4.0	6.0
Interconnection--Avg days to system modification	2.0	4.0	6.0
Interconnection--Estimated vs actual costs	2.0	4.0	6.0
Total	24.3	49.1	75.0

the Company's testimony of the proposed earnings opportunities at "Target" and "Minimum" performance levels in addition to the Maximum performance levels.

For additional context, I have prepared a table that states the potential awards in absolute dollar terms.

"Revenue Opportunities" Associated with Performance on PIMs
Stated as Income Dollars

Category and Supporting Metrics	Min	Target	Max
System Efficiency	336,798	608,108	879,417
Monthly Transmission Peak Demand Reduction	37,422	65,489	93,555
Forward Capacity Market Peak Demand Reduction	224,532	449,064	673,596
EV Off-Peak Charging Rebate Participation	74,844	93,555	112,266
Distributed Energy Resources	**199,459**	**629,812**	**1,103,949**
DG-Friendly Substation Transformers	37,422	224,532	374,220
DR--Connected Solutions Participation	37,422	112,266	187,110
DR--C&I Participation	37,422	112,266	187,110
Electric Heat Initiative	25,073	31,060	74,844
Electric Vehicles	37,422	74,844	130,977
Behind-the-Meter Storage	12,349	37,422	74,844
Utility-Owned Storage	12,349	37,422	74,844
Network Support Services	374,220	598,752	823,284
VVO Pilot Impacts	74,844	74,844	74,844
AMF Customer Engagement and Deployment	74,844	74,844	74,844
Interconnection--Time to ISA	74,844	149,688	224,532
Interconnection--Avg days to system modification	74,844	149,688	224,532
Interconnection--Estimated vs actual costs	74,844	149,688	224,532
Total	910,477	1,836,672	2,806,650

To see why these absolute dollar amounts are too small, consider the parameters for the Electric Heat Initiative. Here the "upside" reward for Maximum Performance in the Electric Heat Initiative is only $75,000, while the award for Minimum Performance in the Electric Heat Initiative is $25,000. It is not reasonable to believe that the difference – $50,000 – is large enough on its own to motivate the program managers to move from Minimum to Maximum performance. Similarly, the amount in play for other important initiatives is very modest, considering the benefits.

My second observation about this scheme is that it is reward-only: there is no penalty for poor performance. The Company has not given meaning to "Minimum," "Target" and "Maximum" for all the performance areas. However, one must assume that "Minimum" performance is acceptable since there is a positive "earnings opportunity" for Minimum performance in each of the categories. Outside of Lake Woebegone, it is very counter-intuitive to reward "Minimum" performance with a bonus ROE. Further, what happens if performance in a category is "Abysmal?" Assumedly, there would be no reward, but neither would there be a penalty.

My third observation is that the National Grid proposal ties potential rewards to the size of the rate base (ROE basis points times rate base). There is no compelling reason to define PIMs this way, and the concept is not consistent with moving utility compensation away from investment levels. Instead, the value at stake with a PIM can be stated simply in dollar terms. Below I demonstrate how this can be accomplished in a flexible model.

Q. WHAT ARE YOUR RECOMMENDATIONS FOR REDESIGNING THE PIMS?

A. In view of the previous discussion, I recommend that the Commission adopt a scoring matrix with the following four changes to the National Grid proposal:

- *Increase the dollar amount at stake.*

- *Uncouple rewards from ROE.*
- *Establish a (possibly non-symmetric) penalty for unacceptable performance.*
- *Allow the matrix to evolve over time, increasing the total stakes.*

There are, of course, many ways to modify National Grid's "revenue opportunity" scheme in a manner that accomplishes these changes. I have prepared a sample scheme that recasts performance levels as familiar letter grades A through F, along with guidance for the award of the letter grades. The matrix contains a wider range of rewards, including penalties for unacceptable performance. It is important to note that this approach is offered as a framework for assessing performance and calculating PIM awards or penalties. The framework does not assume or determine what the appropriate target value is for each of the performance categories.

Illustrative Matrix of Perfomance Rewards

Earnings Maximum		5,000,000
Point Value	$	31,250

	Grade-dependent Points per Performance Category (rounded to integer values)					
	A	B	C	D	F	N/A
Fraction of Grade A	*100%*	*50%*	*20%*	*-15%*	*-40%*	*0%*
System Efficiency	50	25	10	(8)	(20)	0
Monthly Transmission Peak Demand Reduction	6	3	1	(1)	(2)	0
Forward Capacity Market Peak Demand Reduction	36	18	7	(5)	(14)	0
EV Off-Peak Charging Rebate Participation	8	4	2	(1)	(3)	0
Distributed Energy Resources	60	30	12	(9)	(24)	0
DG-Friendly Substation Transformers	18	9	4	(3)	(7)	0
DR--Connected Solutions Participation	10	5	2	(2)	(4)	0
DR--C&I Participation	10	5	2	(2)	(4)	0
Electric Heat Initiative	6	3	1	(1)	(2)	0
Electric Vehicles	8	4	2	(1)	(3)	0
Behind-the-Meter Storage	4	2	1	(1)	(2)	0
Utility-Owned Storage	4	2	1	(1)	(2)	0
Network Support Services	50	25	10	(8)	(20)	0
VVO Pilot Impacts	5	3	1	(1)	(2)	0
AMF Customer Engagement and Deployment	5	3	1	(1)	(2)	0
Interconnection--Time to ISA	14	7	3	(2)	(6)	0
Interconnection--Avg days to system modification	13	7	3	(2)	(5)	0
Interconnection--Estimated vs actual costs	13	7	3	(2)	(5)	0
Total Points per Letter Grade	160	80	32	(24)	(64)	0
Dollar Value	$ 5,000,000	$ 2,500,000	$ 1,000,000	$ (750,000)	$ (2,000,000)	0

Note: Calculated point values are rounded to nearest integer.

A	***Performance in Excellent. Significantly above target.***
B	***Performance is Good. At or above target. No deficiencies.***
C	***Performance is Mediocre. At or slightly below target. Some deficiencies.***
D	***Performance is Unsatisfactory. Below target. Substantial deficiencies.***
F	***Performance is a Failure. No significant accomplishments.***
N/A	***Performance cannot be measured. Accomplishments not possible.***

I stress that this sample scheme is only illustrative; it is flexible and can be adjusted as to the total dollar amount at issue and the relative number of points assigned to each performance category. The sample matrix can be evolved over time without reference to ROE, capital structure, or the size of rate base. Instead, the awards are stated in points that are translated into dollar amounts. This has the effect of making the structure more flexible and moving away from awards that vary with the size of the rate base. Finally, in using this matrix, the Commission can specify the maximum amount available as the total award.

In this illustrative matrix, the total upside amount ("Straight A's") is set at $5,000,000. The impact of this higher total and revised relative values of the letter grades produces some improved results. Going back to the example of the Electric Heat Initiative[12], the maximum award grows from $75,000 to about $188,000. More importantly, the spread between letter grade C (Mediocre) and letter grade A (Excellent) in the Electric Heat Initiative is now $150,000, much larger than the $50,000 spread in the National Grid proposal discussed earlier. I believe this significant difference is much more likely to spur performance past Mediocre toward Excellent.

Another significant difference between this example matrix and the National Grid proposal is the inclusion of negative point values. Under the structure proposed here, National Grid would be penalized for "Unsatisfactory"

[12] By using the Electric Heat Initiative in this example, NECEC and CLF are not taking a position on the merits of the initiative.

performance or "Failure" in a category. The scheme is asymmetric: the potential rewards are significantly larger than the potential penalties.

Q. HOW SHOULD THE "REVENUE OPPORTUNITIES" PRESENTED BY PIMS RELATE TO THE TOTAL COMPENSATION TO NATIONAL GRID?

A. The purpose of PIMs (and incentive regulation generally) is to increase the "value for money" paid by customers to the utility. PIMs should offer utilities the opportunity for increased earnings, but only if their performance rises above a baseline performance that would occur in absence of the PIMs.

To be fair to customers, the Commission must adjust the total allowed non-PIM earnings level so that the sum of non-PIM earnings plus PIM earnings for average performance equals the target revenue. Referring to the example matrix shown above, a letter grade between B and C – essentially C+ -- would equate to "average" performance. In this example, a C+ grade would yield $1.75 million, or about 47 basis points on ROE under the capital structure in this case.

Thus, the Commission should set the total non-PIM earnings $1.75 million below the indicated full cost of service, permitting the utility to recover this deficit through "average" performance, while having the opportunity to earn bonus earnings for superior performance. One direct way to do this is to reduce the awarded ROE by 47 basis points, with additional earnings available to the utility, depending on how it performs. If the Company has a "C+" performance, the utility's earnings will be back to the original target. If it achieves a better grade, total allowed earnings will be correspondingly higher.

Q. PLEASE COMMENT ON THE APPROACH TO PIMS TAKEN BY THE DIVISION IN ITS TESTIMONY IN DOCKET NO. 4770.

A. The Division has taken a principled and sophisticated approach to calculating the appropriate value for performance on each of the PIMs proposed by National Grid. NECEC and CLF support the Division's approach in principle but have not fully analyzed the Benefit/Cost analyses on which the PIM maximum values were set. Further, NECEC and CLF defer to the Division on the appropriate baseline or target values.

Notably, the PIM valuation structure proposed here is not inconsistent with the Division's approach. First, the Division's PIM award levels can be stated in absolute dollar terms and need not be tied to ROE. Second, the Division's approach assumes that the PIM values evolve over time, an outcome enabled by the approach offered here. Third, depending on how total PIM revenues and total non-PIM revenues are synchronized, there is no conflict between the reward/penalty scheme outlined here and a reward-only scheme such as that advocated by the Division.

It is also important to note that the Division opines that the capital investment PIMs would be rendered unneeded if a multi-year rate scheme were employed.

> *Our primary concern with these [Capital Efficiency] PIM[s] is that they are not necessary. As described in the direct testimony of Mr. Woolf, the Division recommends that the Commission establish a multi-year rate plan. Under this proposal the Company*

would automatically have a financial incentive to reduce capital costs and improve productivity between rate cases.[13]

NECEC and CLF agree with this analysis along with the additional observation that a revenue-cap regulatory regime and a multi-year rate plan produce similar incentives for efficiency.

Q. DO YOU HAVE ANY COMMENTS ON THE SPECIFIC PIMS PROPOSED BY NATIONAL GRID?

A. Yes. I have comments on the PIMs that relate to interconnection and the PIMs that relate to electrical storage.

Several PIMs relate to National Grid's relationship with third parties that are interconnecting with National Grid. As gatekeeper to the grid, the distribution utility's performance on these PIMs is critical to the success of an entire industry of companies that provide DERs to customers and to the utility. The distribution company should properly be rewarded for superior performance in this area and several PIMs attempt to measure the Company's performance in this role.

As noted earlier, the UK regulator includes performance on interconnection and customer satisfaction as two of the central "outputs" for the distribution and transmission companies it regulates. In conducting its evaluation of performance, the UK regulator employs surveys of stakeholders and customers

[13] See Attachment C, RIPUC Docket No. 4770. Direct Testimony of Tim Woolf and Melissa Whited, On Behalf of the Division of Public Utilities and Carriers. page 63.

of the regulated companies, including National Grid. Plc, the transmission provider.

National Grid, Plc. has been active in the design and structure of the surveys of stakeholders and customers, the results of which are used to determine the Company's compensation. Consider the following excerpted quotes about the use of a customer survey, taken from a document from the regulator, Ofgem:

> 2.46. NGET has material experience of operating a customer survey and has been able to provide sufficient evidence to set the parameters for this element of the survey in the licence condition, (due to be published shortly). This reflects a baseline score based on NGET's recent overall performance but also supported by similar surveys in other sectors.
>
> * * *
>
> 2.48. We also agree with NGET's proposal to increase the proportion of the incentive driven by the stakeholder survey over the control [period] with the aspiration of it having equal representation towards the end of the price control period when we will understand the results from this new element more fully.[14]

Further, the survey results are very influential in the determination of the companies' compensation.[15]

NECEC and CLF recommend that the Commission direct National Grid in this case to develop customer and stakeholder surveys that can be used to measure the performance of National Grid on its interconnection responsibilities. NECEC

[14] "RIIO-T1: Final Proposals for National Grid Electricity Transmission and National Grid Gas". Ofgem. December 17, 2012.
[15] Performance on the "Customer Satisfaction" measure can affect revenues by plus or minus 1.0 percent. Performance on "Interconnection" can affect total revenues by plus or minus 0.5 percent.

and CLF believe that a survey of interconnection customers, used in combination with numerical performance measures, will present a fuller picture of performance on the interconnection-related PIMs.

Q. WHAT ARE YOUR COMMENTS ON THE STORAGE-RELATED PIMS?

A. Two of the proposed PIMs relate to electrical storage: 1) Utility-Owned Storage and 2) Behind the Meter Storage. Performance on each of these PIMs is measured by the number of MW installed:

> (6) Behind the Meter Storage: measured by the annual MW growth in energy storage installed at customer locations behind a meter used to register electric load; and
>
> (7) Company-Owned Storage: measured by the installed MW of Company-owned in energy storage, inclusive of the ESS Program above, used to support peak load reduction and verified using interval metering.

Once again, National Grid's performance in this area will be crucial to the development of third-party companies that offer storage on both sides of the meter. NECEC and CLF believe that the Company should be measured not simply based on MWs installed, but also on the Company's level of engagement with third-party providers of storage services. Indicia of performance here should begin with a measure of the degree of engagement with third parties. These could include the extent to which the Company engages with third-party storage providers; technical sessions to assist providers in understanding specifications for storage on both sides of the meter; surveys of storage providers measuring their satisfaction with the performance of the Company; and finally, the number of third-parties responding to RFPs for storage services and the number of MW of storage installed by or in partnership with third parties.

C. Recovery of PST-Related Costs

Q. HOW DOES NATIONAL GRID PROPOSE TO RECOVER THE COSTS OF THE PST PROPOSAL?

A. National Grid proposes to create a new cost recovery mechanism – the PST Factor – that would "recover" the added investment from PST projects.

Q. WHAT ARE YOUR CONCERNS ABOUT THE USE OF THE PROPOSED PST COST RECOVERY MECHANISM?

A. I agree with the analysis of the issue contained in the testimony of Tim Woolf on behalf of the Division. Using a "cost tracker" as National Grid proposes damages the planning and regulatory process. In testimony in Docket No. 4770, Mr. Woolf explained that the National Grid proposal "exacerbates the already fractured process for planning, reviewing, and approving utility investments."

If the National Grid proposal is approved, investments in electricity delivery will be split between normal rate cases, ISR filings and PST trackers. These three mechanisms will proceed on different time schedules, will consider overlapping and intersecting sets of capital investments, and will be difficult to oversee in a coordinated manner.

It would be much preferred for all three capital programs to be regulated under a single scheme, preferably in a multi-year revenue control period. That means that the PST costs (capex and opex) would come into rates as long as they are tracking with a plan approved at the front end of a multi-year period. In its testimony, the Division has described how that can occur. NECEC and CLF urge the Commission to reject National Grid's cost recovery and approve a process in line with the Division's position on this issue.

If the Commission declines to adopt a multi-year, revenue cap style of regulation, the Company should be required to file periodic rate cases, as needed, in which the PST costs come into rates. This is a second choice for NECEC and CLF.

Finally, if the Commission declines to adopt either a multi-year rate regime or the requirement that the PST investments enter rates in a rate case, preferring to approve a "cost tracker," it should require the Company to incorporate the PST investments into the cost recovery process for Infrastructure, Safety and Reliability (ISR) costs, the cost recovery process for System Reliability Procurement (SRP) costs, or another existing cost recovery process, as appropriate – NECEC's and CLF's least preferred option.

Q. DO YOU HAVE A RECOMMENDATION FOR THE COMMISSION WITH REGARD TO PROCEDURAL STEPS?

A. Yes. Earlier in testimony, I described the "Grand Bargain" approach to reforming regulation in which the Commission sets the boundaries for a comprehensive multi-year agreement and dispatches the parties to hammer out a proposal that is then considered by the Commission. Due to its complexity, an effective multi-year rate regime – like the Division's proposal or a more structured revenue cap regime – will almost certainly require the use of such a negotiated outcome.

National Grid has filed a traditional rate case with a one-year revenue target and a modest set of PIMs. This filing cannot easily be molded into a multi-year incentive regulation agreement within the limitations of the adjudicatory process under which this docket will proceed. I agree with the Division in its testimony in Docket No. 4470:

> But the Division believes the only practical way that an effective multi-year rate plan can emerge from this rate case is through a negotiated settlement.
>
> * * *
>
> The best result would be a negotiated solution that involves the Company working with the Division and others to address the many complexities. The Division believes this is possible, even with some of the shortcomings present in the Company's current filings. It could be an important first step toward a future ratemaking process.[16]

Of course, NECEC and CLF are willing to engage in a negotiation in this case if the Commission wishes to proceed in that manner.

[16] See Attachment B, RIPUC Docket No. 4770. Direct Testimony of Tim Woolf, On Behalf of the Division of Public Utilities and Carriers. page 43.

Q. WHAT IF THE COMMISSION DOES NOT REQUIRE PARTIES TO NEGOTIATE A MULTI-YEAR RATE PLAN WITHIN THIS CASE?

If the Commission determines that it is obliged to grant rate relief in this case without ordering the parties to develop a multi-year rate plan, then the Commission should 1) grant only interim rates changes that will expire at a future date; and 2) direct the parties to negotiate a comprehensive multi-year rate regime that achieves the purposes defined by the Commission. The expiry of the interim rates will motivate the parties to work expeditiously toward a settlement that will be acceptable to the Commission.

V. CONCLUSIONS AND RECOMMENDATIONS

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS IN THIS CASE.

- Achieving the full vision announced in the PST Report will require fundamental changes to the way the Commission regulates electric utilities. These needed changes were outlined clearly in the PST Report itself and developed by the Commission in its orders in Docket 4600. Rate base rate-of-return regulation, as currently practiced, needs to evolve to a regulatory system that offers National Grid desirable incentives and provides the flexibility for the Company to transform itself to meet the challenges of an evolving electric power sector.
- It is important that the Commission use the opportunity of this case to begin the reform of regulation for National Grid. The Commission should establish a

process that will lead to performance-based "revenue-cap" regulation for National Grid. A significant step toward this goal would be to approve a multi-year rate plan for National Grid such as that recommended by the Division. Otherwise, the combination of National Grid's rate case filing and its PST filing will lock in place a regulatory structure that is being reconsidered (or at least examined) in many state regulatory jurisdictions.

- The proposal of National Grid to incorporate performance measures into its regulation is a modest step in the right direction. Most of the PIMs proposed by National Grid will be helpful, but their application can be improved. More important, the PIMs should be incorporated into a more fundamental reform of regulation, such as a revenue-cap regime or a multiyear plan framework as recommended and outlined by the Division of Public Utilities and Carriers ("DPUC") in its testimony in Docket No. 4770.[17]
- My testimony contains specific recommendations about the structure of some of the proposed PIMs, including the level of reward associated with performance on each PIM.
- The Commission should not create a new "cost tracker" for PST-related costs. If a multi-year rate plan is adopted, these costs will be included in the multi-year revenue cap trajectory. If the Commission allows National Grid to proceed with a

[17] See Attachment B, Direct Testimony of Tim Woolf On Behalf of The Division of Public Utilities and Carriers, Rhode Island Public Utilities Commission Docket No. 4770.

one-year rate plan, the Company should be required to file rate cases to reflect increased PST-related costs.

- Finally, I recommend certain *procedural* steps the Commission should employ to accelerate the move toward a more appropriate regulatory structure. The Commission should either 1) require National Grid to negotiate a multi-year rate plan in this case or 2) grant only interim rate relief, during which period the parties are directed to negotiate a comprehensive revenue cap or multi-year rate plan consistent with Commission directives.

Q. DOES THIS CONCLUDE YOUR TESTIMONY AT THIS TIME?

A. Yes.

ATTACHMENT A

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Employment History

2011-present Principal, Public Policy Consulting

Following my four-year term on the Colorado Public Utilities Commission, I resumed my consulting practice in energy policy and regulation. My focus is on climate, clean tech, regulatory reform, utility business models, integrated resource planning and smart grid.

Current and recent clients include Millennium Challenge Corporation, National Renewable Energy Laboratory, Vote Solar, Hewlett Foundation, the U.S. Department of Energy, Climate Policy Intiative, Steffes Corporation, Posigen, Sunshare, LLC, Vivint Solar, Tendril Networks, Dow Solar, Lawrence Berkeley National Laboratory, Ceres, the Energy Regulatory Commission of Mexico, , Environmental Defense Fund, Earthjustice, Blue Planet Foundation, the Future of Privacy Forum, American Efficient, and Conservation Colorado, among others.

International Engagements

In recent years, I have had assignments in energy policy and regulation in several foreign countries, including Jordan, Malawi, Mexico, Nepal, Sierra Leone, and Tanzania. The activities include developing policy and regulatory roadmaps (Mexico, Nepal), reviewing and drafting legislation (Nepal, Tanzania), advising on electric market structure (Nepal, Malawi) hosting a technical conference (Mexico), designing regulatory agencies (Malawi, Sierra Leone, Nepal, Mexico), advising on natural gas regulation (Tanzania) and developing Smart Grid policy (Mexico).

2013 Nominee, Federal Energy Regulatory Commission

I was nominated by President Obama on June 27, 2013 to serve on the Federal Energy Regulatory Commission and, upon confirmation, to be designated as Chairman. My nomination was vigorously opposed by the coal industry and certain conservative political groups. Following a confirmation hearing, it appeared unlikely that my nomination would be reported favorably by the Senate Energy and Natural Resources Committee. I therefore asked that my name be withdrawn from further consideration.

2011-2013 Senior Policy Advisor, Center for the New Energy Economy

The Center for the New Energy Economy (CNEE) at Colorado State University is headed by former Colorado Governor Bill Ritter, Jr. The Center provides policy makers, governors, planners and other decision makers with a road map to accelerate the nationwide development of a New Energy Economy.

2007-2011 Chairman, Colorado Public Utilities Commission

I was appointed by Governor Bill Ritter, Jr. in January 2007. As Chairman, I helped implement the Governor's and Legislature's vision of Colorado's New Energy Economy, implementing the state's 30% Renewable Energy Portfolio Standard, fulfilling the Commission's role in the Governor's Climate Action Plan, streamlining telecommunications regulation, promoting broadband telecommunications investment and improving the operation of the Commission.

Here are some major accomplishments during my term on the Commission:

- **Implementing the Clean Air-Clean Jobs Act (2010).** Following passage of this new law in 2010, the Commission worked under a very compressed time schedule to examine proposals by XcelEnergy and Black Hills Energy to reduce pollutants from their coal fired generation plants. The contentious Xcel proceeding involves thirty-four legal parties, testimony from sixty-one witnesses and the consideration of more than a dozen contending compliance plans. The case required the close cooperation between the Commission and the Colorado Department of Public Health and Environment, the first such collaboration.

- **Implementing dozens of new energy, transportation and telecommunications laws.** In each legislative session during the term of Governor Ritter, the general assembly passed numerous sweeping utility-related laws. Many of these new laws required the Commission to adopt rules, compile reports, or conduct hearings. Rarely in Colorado history has there been this much activity required of the Commission.

- **Modifying and approving the electric resource plan of XcelEnergy (2009)**. After extensive hearings, the Commission approved a plan that includes large amounts of new wind capacity, the early closure of two coal power plants to reduce carbon and other emissions, the acquisition of 200-600 megawatts of solar thermal capacity, and substantial amounts of new energy efficiency savings. The target portfolio would reduce CO_2 emissions per megawatt-hour by 22% from current levels over eight years. The Commission decision required competitive acquisition for new resources.

- **Adopting new, aggressive energy efficiency requirements (2008)** for Colorado gas and electric utilities. The Commission's requirements for electric utilities go well beyond the statutory minimum levels enacted in 2007. The Commission's policies also provided for rapid cost recovery of energy efficiency spending and bonus incentives for superior performance for the utilities.

- **Rewriting the Commission's electric resource planning rules (2007)** to require full consideration of future costs for carbon emissions, new clean energy resources and environmental and economic externalities. Retained and refined the requirements for competitive acquisition of new resources.

- **Improving communications with stakeholders.** I successfully sought legislation to modify the Commission's enabling statute, allowing the use of a "permit-but-disclose" communications process like the one employed successfully by the Federal Communications Commission and the FERC. The result has been much greater exposure of the Commissioners and staff (outside the hearing process) to the thinking of consumers, utilities, environmental advocates, large customers, advocates for new technologies, etc.

- **Organizing meetings of Western state regulators on regional transmission issues**. We discussed coordination in our efforts to add transmission capacity, especially to renewable energy zones. In future meetings we will discuss a goal of eliminating "pancaked" transmission pricing in the intermountain west.

- **Conducting hearings in eight towns around the state** on a "road trip" to collect consumer opinions about energy rates, distributed generation, the future of the energy sectors, and support for moving toward a more environmentally-sensitive utility industry.

- **Reorganizing the PUC's staff** to create a Research and Emerging Issues section. As chairman, I worked to improve deployment of the agency's modest staff so that the Commissioners could stay apprised of new technology and policy alternatives and be able to investigate and implement new regulatory approaches.

- **Reaching out to consumers and interest groups.** I frequently spoke at meetings of consumer organizations, environmental groups, business and professional associations, legal seminars, etc. The two-way-street communications improves my understanding and conveys to the public the immense challenges we face in energy policy with climate change.

1995-2006 President, Public Policy Consulting

Consultant, specializing in energy and telecommunications regulatory policy issues. Assignments include strategic counsel to clients and research and testimony before regulatory and legislative bodies. In addition, I produced several research reports about the impact on rates of adding significant amounts of wind and solar capacity to utility systems. These reports are listed below.

I had a wide range of clients, including: consumer advocate offices, rural electric utilities, senior citizen advocacy groups, environmental groups, industrial electric users, homebuilders, building managers, telecommunications resellers, incumbent local exchange companies, low-income advocacy organizations, and municipal utilities. I testified as an expert witness before regulatory commissions in twelve states.

1996-2003 President and Policy Director, Competition Policy Institute

Competition Policy Institute was an independent non-profit organization that advocated for state and federal policies to bring competition to energy and telecommunications markets in ways that benefit consumers. Duties included: determining the organization's policy position on a wide range of telecommunications and energy issues; conducted research, produced policy papers, presented testimony in regulatory and legislative forums, hosted educational symposia for state regulators and state legislators.

1984-1995 Director, Colorado Office of Consumer Counsel

Director of Colorado's first state-funded utility consumer advocate office. By statute, the OCC represents residential, small business and agricultural utility consumers before state and federal regulatory agencies. The office was a party to more than two hundred legal cases before the Colorado Public Utilities Commission, the Federal Communications Commission, the Federal Energy Regulatory Commission and the courts.

Managed a staff of eleven, including attorneys, economists, and rate analysts who conduct economic, financial and engineering research in public utility matters. Testified as an expert witness on subjects of utility rates and regulation. Negotiated rate settlement agreements with utility companies. Regularly testified before the Colorado general assembly and spoke to professional business and consumer organizations on utility rate matters. Consulted with advisory board of consumer leaders from around the state.

Held leadership roles in National Association of State Utility Consumer Advocates. Member of high-level advisory boards to Federal Communications Commission (Network Reliability Council and North American Numbering Council) and Environmental Protection Agency (Acid Rain Advisory Council). Frequent witness before congressional committees and invited speaker before national industry and regulatory forums.

1977-1984 Consulting Utility Rate Analyst

Represented clients in public utility rate cases and testified as an expert witness in utility cases before regulatory commissions in Utah, Wyoming, Colorado and South Dakota. Clients included state and local governments, low income advocacy groups, irrigation farmers and consumer groups. Testimony spanned topics of telephone rate design, electric cost-of-service studies, avoided cost valuation of nuclear generation, electric rate design for irrigation customers and municipal water rate design.

1975-1984 Instructor in Mathematics

Taught mathematics at the University of Colorado, Denver and Boulder campuses. Nominated three times for outstanding part-time faculty member.

1971-1974 Manager, Blue Cross and Blue Shield

Managed major medical claims processing department. Responsibilities included budgets, hiring, training, managing supervisors, and coordinating with medical peer review committee.

Other Business Interests

1994-2011 Managing Partner, Trail Ridge Winery

Managing Partner and Secretary/Treasurer of Trail Ridge Winery. Trail Ridge Winery was located in Loveland, Colorado, and produced a variety of award-winning wines from Colorado-grown grapes.

Education

M.A. (Mathematics) 1977. University of Colorado. Course requirements met for Ph.D.

Graduate courses toward M.A. in Economics 1981-1984. University of Colorado. Twenty-seven hours including Economics of Regulated Industries, Natural Resource Economics, Econometrics.

B.A. with Honors (Philosophy) 1971. St. Louis University.

Professional Associations and Activities

Selected Current and Recent:

Board of Directors, Nikola Power

Board of Directors, Smart Electric Power Alliance (SEPA)

Board of Directors, Southwest Energy Efficiency Project

Board of Directors, Western Resource Advocates

Board of Directors, GRID Alternatives Colorado

Brookings Institution, Non-resident Senior Fellow, 2013-2014

Harvard Electric Policy Group, John F. Kennedy School, Harvard University 1994-present

Advisory Council to the Board of the Electric Power Research Institute (EPRI) 2008-2011

Keystone Energy Board 2009-2012

Aspen Institute for Humanistic Studies, Communications and Society Programs 1986-present

Selected Past:

National Association of Regulatory Utility Commissioners
- Member, Energy Resources and Environment Committee 2007-2011
- Member, International Relations Committee 2007-2011
- Chair, NARUC Task Force on Climate Policy 2010-2011
- President, Western Conference of Public Service Commissioners, 2010-2011

Acid Rain Advisory Council to the Environmental Protection Agency, circa 1991
American Association for the Advancement of Science
American Vintners Association (*now* WineAmerica), Executive Committee, Membership Chair
Colorado Common Cause, Board Member
Colorado Energy Assistance Foundation, Board Member, Past President
Colorado Legislative Task Force on Information Policy, Gubernatorial Appointee 2000-2001
Colorado Public Interest Research Foundation, Board Member
Colorado Telecommunications Working Group, Gubernatorial Appointee
Colorado Wine Industry Development Board, Chairman
Council on Economic Regulation, Past Fellow
Denver Mayor's Council on Telecommunications Policy
Exchange Carriers Standards Association Network Reliability Steering Committee
Legislative Commission on Low-Income Energy Assistance, Past President
National Association of State Utility Consumer Advocates
    President 1991-1992, Vice-President 1990, Treasurer 1987-1989
    Chair, Telecommunications Committee 1992-1995
Network Reliability Council to the Federal Communications Commission
New Mexico State University Public Utilities Program, Faculty and Advisory Council
North American Numbering Council to Federal Communications Commission, Co-Chair
Outreach Committee, Western States Coordinating Council Regional Planning Committee
Total Compensation Advisory Council to the State of Colorado Department of Personnel
Who's Who in Denver Business

Selected Regulatory Testimony

From 1977 to 2018, Mr. Binz participated in more than 150 regulatory proceedings before the Federal Communications Commission, the Federal Energy Regulatory Commission, State and Federal District Courts, the 8th Circuit, 10th Circuit and D.C. Circuit Courts of Appeal, the U.S. Supreme Court and state regulatory commissions in Arizona, California, Colorado, Georgia, Hawaii, Idaho, Massachusetts, Maine, Missouri, New York, North Dakota, South Dakota, Texas, Utah, and Wyoming. He has filed testimony in approximately sixty proceedings before these bodies. His testimony and comments have addressed a wide variety of technical and policy issues in telecommunications, electricity, natural gas and water regulation.

Before the Public Utility Commission of Hawaii. In the Matter of the Application of HAWAIIAN ELECTRIC COMPANY, INC. For Approval of General Rate Case and Revised Rate Schedules and Rules. Docket No. 2016-0328. Topic: Proposal for Incentive Based Regulation.

Before the Massachusetts Department of Public Utilities. Petition of NSTAR Electric Company and Western Massachusetts Electric Company each d/b/a Eversource Energy for Approval of an Increase in Base Distribution Rates for Electric Service Pursuant to G.L. c. 164, § 94 and 220 C.M.R. § 5.00. April 2017. Topic: Proposal for Incentive Based Regulation.

Before the Public Utility Commission of Hawaii. In the Matter of the Application of HAWAIIAN ELECTRIC COMPANY, INC., HAWAI'I ELECTRIC LIGHT COMPANY, INC., MAUI ELECTRIC COMPANY, LIMITED, and NEXTERA ENERGY, INC., For Approval of the Proposed Change of Control and Related Matters. "Testimony of Ronald J. Binz." January 2016. Topic: Conditions to be attached to merger approval.

Before the Public Service Commission of New York. Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision. Case 14-M-0101. "Statement of Ronald J. Binz on Behalf of Earthjustice In Reply to Parties' Initial Comments on the Staff Straw Proposal" October 2014. Topic: Regulatory approach in the Commission's REV proposal.

Before the Public Service Utility Commission of Hawaii. Instituting an Investigation to Reexamine the Existing Decoupling Mechanisms for Hawaiian Electric Company, Inc., Hawaii Electric Light Company, Inc., and Maui Electric Company, Limited. Docket No. 2013-0141. "Declaration of Ronald J. Binz." September 2014. Topic: Proposal for Incentive Regulation of HECO.

Before the Public Utilities Commission of California. Order Instituting Rulemaking to Enhance the Role of Demand Response in Meeting the State's Resource Planning Needs and Operational Requirements. Rulemaking 13-09-011. Comments and oral testimony of Ronald J. Binz before the Administrative Law Judge. August 2014.

Before the Public Service Commission of Wyoming. In The Matter of Rocky Mountain Power's Confidential Contract Filing Docket No. 20000-379-EK-10 of a Purchase Power Agreement between PacifiCorp and Pioneer Wind Park I. Binz Affidavit on behalf of Northern Laramie Range Alliance. Record No. 12618 (August 2011)

Before the West Virginia Public Service Commission. In The Matter Of the Petition of Verizon West Virginia, Inc. To Cease Rate Regulation of Certain Workably Competitive Telecommunications Services. Case No. 06-0481-T-PacifiCorp (June 2006)

Before the Utah Public Service Commission. In The Matter Of The Division's Annual Review and Evaluation of Electric Lifeline Program, HELP Rate Design Testimony. Docket No. 04-035-21 (September 2005)

Before the Colorado Public Utilities Commission. Testimony on behalf of YMCA of the Rockies. In re: YMCA of the Rockies, Complainant v. Xcel Energy (d/b/a Public Service Company of Colorado, Respondent. Rebuttal Testimony. Docket No. 05F-167G. (September 2005)

Before the Colorado Public Utilities Commission. Testimony on behalf of YMCA of the Rockies. In re: YMCA of the Rockies, Complainant v. Xcel Energy (d/b/a Public Service Company of Colorado, Respondent. Direct Testimony. Docket No. 05F-167G. (June 2005)

Before the Michigan Public Service Commission. Testimony on behalf of the Michigan Attorney General. In The Matter Of SBC Michigan's Request For Classification Of Business Local Exchange Service As Competitive Pursuant To Section 208 Of The Michigan Telecommunications Act. Case No. U-14323. (March 2005)

Before the Colorado Public Utilities Commission. Testimony on behalf of the Colorado Office of Consumer Counsel. In the Matter of the Combined Application of Qwest Corporation for Reclassification and Deregulation of Certain Part 2 Products and Services and Deregulation of Certain Part 3 Products and Services. Docket No. 04A-411T. (February 2005)

Before the Utah Public Service Commission. In The Matter Of the Application of PacifiCorp for Approval of Its Proposed Electric Rate Schedules and Electric Service Regulation. Rate Design Testimony. Docket No. 04-035-42. (January 2005)

Before the Utah Public Service Commission. In The Matter Of the Application of PacifiCorp for Approval of Its Proposed Electric Rate Schedules and Electric Service Regulation. Revenue Requirements Testimony. Docket No. 04-035-42. (December 2004)

Before the Colorado Public Utilities Commission. Testimony on behalf of the Building Owners and Managers Association of Metropolitan Denver (BOMA) in the Matter of The Investigation And Suspension Of Tariff Sheets Filed By Public Service Company Of Colorado With Advice Letter No. 1411—Electric Docket No. 04S-164E (October 2004)

Before the Colorado Public Utilities Commission. Testimony on behalf of Colorado Energy Consumers in the Matter of The Application of Public Service Company of Colorado for Approval of its 2003 Least-Cost Resource Plan. Docket No. 04A-214E (filed: September 2004)

Before the Colorado Public Utilities Commission. Testimony on behalf of Colorado Energy Consumers in the Matter of the Application of Public Service Company of Colorado For An Order Authorizing It To Implement A Purchased Capacity Cost Adjustment Rider In Its PUC No. 7 – Electric Tariff. Docket No. 03A-436E. (filed: March 2004)

Before the Wyoming Public Service Commission. Testimony on behalf of Wyoming Industrial Energy Consumers (WIEC) and AARP In the Matter of the Application of PacifiCorp for Approval of a Power Cost Adjustment Mechanism. Docket No. 20000- ET-03-205 (filed: January 2004).

Before the Colorado Public Utilities Commission. Testimony on behalf of the Colorado Office of Consumer Counsel Regarding The Unbundling Obligations Of Incumbent Local Exchange Carriers Pursuant To The Triennial Review Order – Initial Commission Review. Docket No. 03I-478T. (January 2004)

Before the Wyoming Public Service Commission. Testimony on behalf of AARP in the matter of The Application Of PacifiCorp For A Retail Electric Utility Rate Increase Of $41.8 Million Per Year Docket No. 20000-ER-03-198 (January 2004).

Before the Wyoming Public Service Commission. Public hearings testimony on behalf of AARP in the matter of an application by Kinder Morgan to modify the provider selection process in its Choice Gas Program. (December 2003).

Before the Public Service Commission of North Dakota. Testimony on behalf of AARP in the matter of In the Matter of the Notice of Montana-Dakota Utilities Co. for an Electric Rate Change. Case No. PU-399-03-296. (October 2003)

Before the Colorado Public Utilities Commission. Testimony in the matter of Public Service Company of Colorado's Advice Letter No. 598 – Natural Gas Extension Policy. Docket No. 02S-574G. (March 2003)

Before the Colorado Public Utilities Commission. Testimony in the remand hearings in the formal complaint case of the Homebuilders Association of Metropolitan Denver against Public Service Company. Docket 01F-071G. (January 2003)

Before the Wyoming Public Service Commission. Testimony on behalf of AARP in the matter of an application by PacifiCorp to increase rates, recover excess net power costs, and recover purchase power costs related to the Hunter Unit 1 outage. Docket No. 20000-ER-02-184. Testimony Concerning A Proposed General Rate Increase And Surcharge For Previous Power Costs. (November 2002).

Before the Wyoming Public Service Commission. Testimony on behalf of AARP in the matter of an application by PacifiCorp to increase rates, recover excess net power costs, and recover purchase power costs related to the Hunter Unit 1 outage. Docket No. 20000-ER-02-184. Testimony Concerning Hunter Unit 1 Issues. (November 2002).

Before the Colorado Public Utilities Commission. Comments on behalf of the Colorado Energy Assistance Foundation. Docket No. 02R-196G. In the Matter of the Proposed Repeal and Reenactment of the Rules Regulating Gas Utilities. (November 2002)

Before the Colorado Public Utilities Commission. Testimony on behalf of Colorado Energy Assistance Foundation and Catholic Charities of the Archdiocese of Denver. Docket No. 02A-158E. In the Matter of the Application of Public Service Company of Colorado for an Order to Revise its Incentive Cost Adjustment. (April 2002)

Before the Idaho Public Utilities Commission. Testimony on behalf of Astaris, in the matter of Case No. IPC-E-01-43 concerning the buy-back rates under an electric load reduction program. (January 2002)

Before the Colorado Public Utilities Commission. Testimony in matter of the investigation of Advice Letters 579 and 581 of Xcel Energy on behalf of Homebuilders Association of Denver. Dockets 01S-365G and 01S-404G. (January 2002)

Before the Colorado Public Utilities Commission. Testimony in the formal complaint case of the Homebuilders Association of Metropolitan Denver against Public Service Company. Docket 01F-071G. (August 2001)

Before the Colorado Public Utilities Commission. Testimony in the matter of the investigation and suspension of Advice Letter No. 566 of Xcel Energy on behalf of the Homebuilders Association of Metropolitan Denver. Docket No. 00S-422G. (November 2000)

Before the American Arbitration Association. In the Matter of Univance Telecommunications, Inc. v. Venture Group Enterprises, Inc. Arbitration No. 77 Y 147 00099 00 (November 2000)

Testimony of Ronald Binz at FCC Public Forum on SBC/Ameritech merger (May 1999)

Docket No. 97-106-TC -- Testimony of Ron Binz before New Mexico State Corporation Commission on Investigation Concerning USWest's Compliance with Section 271(c) of the Telecommunications Act (July 1998)

Before the Colorado Public Utilities Commission. Testimony Concerning the Investigation of Telephone Numbering Policies. (March 1998)
Docket No. 6717-U □ Testimony before the Georgia Public Service Commission Concerning the Service Provider Selection Plan of Atlanta Gas Company. (January 1997)

Case 96-C-0603 and Case 96-C-0599--Testimony of Ronald J. Binz on behalf of CPI before the New York State Public Service Commission concerning the Bell Atlantic/NYNEX Merger (November 1996)

Docket No. 96-388 - Direct Testimony of Ronald J. Binz, CPI, On Behalf of the Office of the Public Advocate (October 1996) State of Maine, Public Utilities Commission Joint Petition of New England Telephone and Telegraph Company and NYNEX Corporation for Approval of the Proposed Merger of a Wholly-Owned Subsidiary of Bell Atlantic Corporation into NYNEX Corporation.

Application No. 96-04-038 - Direct Testimony of Ronald J. Binz, CPI, On Behalf of Intervener, Utility Consumers Action Network (September 1996) Before the Public Utilities Commission of the State of California In the Matter of the Joint Application of Pacific Telesis Group (Telesis) and
SBC Communications (SBC) for SBC to Control Pacific Bell (U 1001 C), Which Will Occur Indirectly as a Result of Telesis' Merger With a Wholly Owned Subsidiary of SBC, SBC Communications (NV) Inc.

Presentation to Federal-State Joint Board on Universal Service (April 12, 1996)

Testimony before the Texas Public Utility Commission on the Integrated Resource Planning Rule (March, 1996)

Congressional Testimony

Mr. Binz has appeared sixteen times before U.S. House and Senate Committees. In addition, he has testified numerous times before state legislatures in several states. Here is a list of his U.S. Congressional testimony and statements:

United States Senate Energy and Natural Resources Committee, 2013. Statement in support of my nomination to the Federal Energy Regulatory Commission.

United States House of Representatives Commerce Committee, Energy Subcommittee, 2008. Testimony concerned a proposal to adopt a federal renewable energy standard.

United States House of Representatives Judiciary Committee, November 1999. Testimony concerning H.R. 2533, The Fairness in Telecommunications License Transfer Act of 1999.

United States Senate Judiciary Committee; Antritrust, Business Rights and Competition Subcommittee, April 1999. Testimony concerning S.467, The Antitrust Merger Review Act.

United States Senate Commerce Committee, Telecommunications Subcommittee, May 1998. Testimony in oversight hearings concerning the performance of the Common Carrier Bureau of the Federal Communications Commission.

United States Senate Judiciary Committee, Washington, D.C., September 1996. Presented testimony on behalf of the Competition Policy Institute on the competitive impact of proposed mergers of Regional Bell Operating Companies.

United States House of Representatives Subcommittee on Telecommunications and Finance of the Committee on Commerce, May 1995. Testimony presenting NASUCA’s position on H.R. 1555 by Representative Fields.

United States Senate Subcommittee on Antitrust, Washington, D.C., September 1994. Testimony presenting NASUCA's position on S. 1822 by Senator Hollings.

United States House of Representatives Subcommittee on Telecommunications and Finance of the House Energy and Commerce Committee, Washington, D.C., February 1994. Presented testimony on H.R. 3636.

United States House of Representatives Subcommittee on Economics and Commercial Law, Washington, D.C., October 1992. Supplemental testimony presenting NASUCA's position on legislation concerning the Modified Final Judgment introduced by Representative Brooks.

United States House of Representatives Subcommittee on Telecommunications and Finance, Washington, D.C., October 1991. Testimony on RBOC entry into telecommunications manufacturing and information services.

United States House of Representatives Subcommittee on Economics and Commercial Law, Washington, D.C., August 1991. Testimony presenting NASUCA's position on possible federal legislation concerning the Modified Final Judgment.

United States Senate Subcommittee on Energy Regulation and Conservation, Denver, Colorado, April 1991. Testimony presenting NASUCA's position on federal legislation concerning regulation of the natural gas industry, introduced by Senator Wirth.

United States Senate Communications Subcommittee, Washington, D.C., February 1991. Testimony on behalf of NASUCA concerning S.173, telecommunications legislation introduced by Senator Ernest Hollings.

United States Senate Communications Subcommittee, Washington, D.C., July 1990. Testimony on behalf of NASUCA concerning S.2800, telecommunications legislation introduced by Senator Conrad Burns.

United States House of Representatives Subcommittee on Telecommunications and Finance, July 1988. Testimony on the FCC Price Cap proposal.

Reports and Articles

Title	Publisher	Date
Considerations for the Governance of a Western Regional System Operator	Public Policy Consulting	March 2016
Practicing Risk Aware Electricity Regulation: 2014 Update	Ceres	November 2014
Priorities after FERC Overture	EnergyBiz Magazine	Jan-Feb 2014
Risk-Aware Planning and a New Model for the Utility-Regulator Relationship	ElectricityPolicy.com	July 2012
Practicing Risk Aware Electricity Regulation: What Every State Regulator Needs to Know	Ceres	April 2012
Conquering Consumer Resistance: Time to cross the bridge to time-of-use rates	EnergyBiz Magazine	March-April 2012
Cap and Innovate: An alternative approach to climate regulation.	Public Utilities Fortnightly	June 2010
Wind on the Public Service Company of Colorado System: Cost Comparison to Natural Gas	Interwest Energy Alliance (with Jane Pater)	August 2006
The Impact of the Renewable Energy Standard in Amendment 37 on Electric Rates in Colorado	Public Policy Consulting	September 2004
The Impact a Renewable Energy Portfolio Standard On Retail Electric Rates In Colorado	Public Policy Consulting	February 2004
Qwest, Consumers and Long Distance Entry: A Discussion Paper	Public Policy Consulting	October 2001
Addressing Market Power: The next step in electric restructuring	Competition Policy Institute	June 1998
Navigating a Course to Competition: A consumer perspective on electric restructuring	Competition Policy Institute	August 1997

ATTACHMENT B

Before the
Rhode Island Public Utilities Commission

Proceeding on the Narragansett Electric	)	
Company d/b/a National Grid Proposed	)	Docket No. 4770
Tariff Changes	)	

Direct Testimony of
Tim Woolf

On Behalf of

The Division of Public Utilities and Carriers

April 6, 2018

Table of Contents

1. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, title, and employer.

A. **Mr. Woolf:** My name is Tim Woolf. I am the Vice President at Synapse Energy Economics, located at 485 Massachusetts Avenue, Cambridge, MA 02139.

Q. Please describe Synapse Energy Economics.

A. Synapse Energy Economics is a research and consulting firm specializing in electricity and gas industry regulation, planning, and analysis. Our work covers a range of issues, including economic and technical assessments of demand-side and supply-side energy resources; energy efficiency policies and programs; integrated resource planning; electricity market modeling and assessment; renewable resource technologies and policies; and climate change strategies. Synapse works for a wide range of clients, including state attorneys general, offices of consumer advocates, trade associations, public utility commissions, environmental advocates, the U.S. Environmental Protection Agency, U.S. Department of Energy, U.S. Department of Justice, the Federal Trade Commission, and the National Association of Regulatory Utility Commissioners. Synapse has over 25 professional staff with extensive experience in the electricity industry.

Q. Please summarize your professional and educational experience.

A. **Mr. Woolf:** Before joining Synapse Energy Economics, I was a commissioner at the Massachusetts Department of Public Utilities (DPU) from 2007 through 2011. In that capacity, I was responsible for overseeing a substantial expansion of clean energy policies, including significantly increased ratepayer-funded energy efficiency programs;

an update of the DPU energy efficiency guidelines; the implementation of decoupled rates for electric and gas companies; the promulgation of net metering regulations; review and approval of smart grid pilot programs; and review and approval of long-term contracts for renewable power. I was also responsible for overseeing a variety of other dockets before the Commission, including several electric and gas utility rate cases.

Prior to being a commissioner at the Massachusetts DPU, I was employed as the Vice President at Synapse Energy Economics; a Manager at Tellus Institute; the Research Director at the Association for the Conservation of Energy; a Staff Economist at the Massachusetts Department of Public Utilities; and a Policy Analyst at the Massachusetts Executive Office of Energy Resources.

I hold a Masters in Business Administration from Boston University, a Diploma in Economics from the London School of Economics, a BS in Mechanical Engineering and a BA in English from Tufts University. My resume is attached as Exhibit TW/MW-1.

Q. **Have you any additional professional experience that is directly relevant to this case or your testimony in it?**

A. Yes. In 2012 and 2013 I was one of the co-facilitators of the Massachusetts Grid Modernization Collaborative sponsored by the Massachusetts Department of Public Utilities. In 2016 and 2017 I was one of the co-facilitators of the New Hampshire Grid Modernization Working Group sponsored by the New Hampshire Public Utilities Commission. In addition, in 2017 I served as a consultant expert witness to Advanced Energy Economy in its intervention in National Grid's rate case before the New York Public Service Commission. Finally, I am the author of several academic and policy articles related to performance-based ratemaking. A list of my publications related to power sector transformation is provided in my resume.

Q. On whose behalf are you testifying in this case?

A. I am testifying on behalf of the Division of Public Utilities and Carriers (the Division).

Q. Have you previously testified before the Rhode Island Public Utilities Commission?

A. Yes. I have testified before the Rhode Island Public Utilities Commission (the Commission) on behalf of the Division in National Grid's (the Company's) Energy Efficiency and System Reliability Plans. For the last decade I have represented the Division in meetings with the Energy Efficiency Collaborative and have helped to structure the energy efficiency and system reliability and procurement performance incentive mechanisms. In addition, I participated on behalf of the Division in the Docket 4600 Working Group, and I assisted the Division with the Rhode Island Power Sector Transformation report recently submitted to Governor Raimondo. I also recently testified before the Commission on behalf of the Division in Docket 4783 on National Grid's proposed AMF pilot.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present an overview of the Division's case, to identify policy objectives that shape a long-term vision for continuing the transformation of Rhode Island's power sector, and to outline a rate plan proposal that offers the Company and ratepayers key protections during a period of rapid changes to the technologies and services of the electric distribution utility.

2. OVERVIEW OF THE CASE

Q. Does the Division agree that the Company is entitled to the rate relief being requested in this case?

A. No. The Division does not agree with the rate request made by the Company in this case, even after its original request was lowered on March 2, 1018.

Q. Please provide a brief summary of how and why the Company's request for rate relief changed after the initial filing.

A. The Company's original filing, prior to the change in the federal tax laws, requested a total combined increase of approximately $71.6 million – $41.3 million for the electric distribution business and $31 million for the gas distribution business. After the corporate tax rate was reduced to 21%, the Company revised its revenue requirement to reduce the combined total request by approximately $19.3 million. The Division, early on in this case, also found an error made by the Company in the calculation of deferred taxes of approximately $6.7 million. On March 2, the Company then filed with the Commission a new revenue requirement reducing its request for a rate increase to take into account the change in tax rate and the deferred tax error. As a result, the Company's revised request was reduced to approximately $45.6 million – $27.2 million for electric and $18.4 million for the gas business.

Q. Does the Division agree that the Company is entitled to rate increases in the amounts reflected in its adjusted request?

A. No. The Division has done a thorough review of the Company's case, issuing hundreds of data requests probing the justification put forth by the Company for its rate request.

To date, as reflected in the Division's calculation of the revenue requirement for the rate year, the Division believes the Company's adjusted request should be substantially reduced even further. Specifically, after making numerous adjustments, the Division is recommending a reduction in the rate request, as reflected in its March 2 revenue requirement, by a combined total of $34.5 million – lowering the request on the electric side by approximately $18.5 million and the request on the gas side by approximately $16 million. As a result, the Division believes the Company at this time should not be allowed to increase its electric and gas distribution rates by more than $8.9 million for the electric business and $2.4 million for the gas business – or by no more than combined total of $11.3 million, representing a cut in the combined rate request of 75% from the revised filing on March 2, 2018.

Q. What is the Company requesting for its allowed return on equity?

A. The Company is requesting a return on equity of 10.1% for both the electric and gas businesses.

Q. Does the Division agree with this request?

A. No. The Division believes this request is excessive and, instead, recommends a return on equity of 8.5% for the electric business and 9% for the gas business. The Division's calculation of the revenue requirement reflects these reduced returns.

Q. Please describe very briefly other matters and issues the Division is addressing in this case, other than the revenue requirement.

A. In addition to addressing the request for a distribution rate increase, the Division believes it is extremely important for the Commission in this rate case to take the first significant steps to address the changing landscape of the electric distribution business. As I will explain more fully in this testimony, there is a need to modernize the grid and make it ready for significant change. The Company needs to be implementing new initiatives as an integral part of its distribution business, not as stand-alone projects. For reasons I will explain in depth, the Division is recommending that many of the initiatives being proposed under the umbrella of "Power Sector Transformation" in Docket 4780 need to be addressed in this overall rate case, including the means through which the Company recovers its costs. For that reason, the Division is recommending the Commission take important steps to align the electric business with the related ratemaking process for the future by addressing some of the foundational matters in an integral way in this case and establishing a roadmap for future planning at the same time.

Q. Please list some of the more significant ratemaking issues the Division is recommending the Commission address.

A. There are many. Broadly speaking, however, these are some of the key points:

- Establishing a ratemaking framework that utilizes multi-year rate plans as the means for integral long-term planning,
- Addressing the Company's requests for cost recovery for its grid modernization and Power Sector Transformation projects through base distribution rates, rather than a fully reconciling rate mechanism such as the "PST Tracker" proposed by the Company for its grid modernization and related activities,

- Creating a capital efficiency mechanism that integrates capital planning under the ISR with multi-year rate plans, including an incentive mechanism that encourages cost control discipline,
- Establishing a new set of performance-based incentive mechanisms (PIMs) that send clear financial signals to the Company to accomplish targeted goals that lower peak electricity usage, lower greenhouse gas emissions, stabilize costs, and meet other important long-term objectives relating to the integration of distributed energy resources, and
- Recognizing the need to have PIMs established at the same time as the Company's return on equity is set in the rate case, and adjusting the Company's earnings sharing mechanism to take these related components into account to encourage efficient business practices while at the same time protecting ratepayers from excessive utility earnings.

Q. What are some of the initiatives the Division is recommending move forward now?

A. One of the most important initiatives is for the Company to move forward with a study that provides the pathway leading to the potential deployment of Advanced Metering Infrastructure (AMI). This should take place in conjunction with parallel activities taking place in New York with the Company's affiliate, and Rhode Island's fair share of the costs amortized and included in base distribution rates. In addition, the Division is recommending the Company commence immediately the proposed enhancements to the GIS system in conjunction with New York and the costs included in base distribution rates. The Division also is recommending that the Company move forward with the System Data Portal, and the adjusted costs included in base distribution rates. The

Division also believes it is critical that a directive be given to the Company to perform a comprehensive Grid Modernization study and produce a plan that is filed with the Commission around the same time that the AMI Study is produced and filed. The Company also should commence the steps necessary to implement a new DSCADA system, the costs of which would eventually be recovered in base distribution rates. Finally, the Commission should direct the Company to file a multi-year rate plan no later than early 2020, to set new rates three years after the rates from this rate case go into effect. With these steps, the foundation for the future operation of the distribution business, aligned with integrated planning and ratemaking, will be established.

For the reasons that will be described in my testimony, the Division believes the negotiation of a multi-year rate plan in this case would be very desirable. However, even if that cannot be achieved, there are important steps the Commission can take in this case, and principles that can be established, that directionally set multi-year rate planning as an important long-range planning and ratemaking tool for the future.

Q. Please identify the Division's witnesses, and the matters each of them will address in this rate case.

A. The Division's case is comprised of ten witnesses on the following subjects:

(1) <u>Overview and Policy Vision – Tim Woolf</u>: This my testimony here, which presents a policy vision for how this rate case fits into the ongoing transformation of the electric power sector and how the structure of a multi-year rate plan, rather than the Company's proposed tracker mechanism, is best suited to protect Rhode Island ratepayers during a period of technology change;

(2) Revenue Requirement – Michael Ballaban and David Effron: The Division's adjustments to the Company's proposed revenue requirement for the rate year is provided by Michael Ballaban and David Effron;

(3) Review of Gas Business Enablement – Tina Bennett: Ms. Bennett addresses the Company's transformative gas business initiative;

(4) Reviewing Foundational Electric Distribution Initiatives – Greg Booth: Mr. Greg Booth's testimony provides an evaluation of the foundational distribution initiatives that need to be addressed in this rate case, that were also included in the Company's original PST filing that was transferred to Docket 4780;

(5) Return on Equity – Matt Kahal: The Division's recommendation for a return on equity for the Company's electric and gas distribution businesses is addressed by Mr. Matt Kahal;

(6) Benefit/Cost Ratios, PIMS, and Earnings Sharing – Tim Woolf and Melissa Whited: I join in a panel with Melissa Whited to address the benefit cost analysis used for evaluating new transformative projects. We also propose a series of new performance-based mechanisms that are designed to work in tandem with the Company's return on equity and earnings sharing mechanism;

(7) Depreciation – Roxie McCullar: The Company's depreciation study is evaluated by Ms. Roxie McCullar;

(8) Income Eligible Discount A-60 Rates – Roger Colton: The Division's recommendation for an enhanced low income discount is addressed by Mr. Roger Colton;

(9) Electric Rate Design – John Athas: The Company's allocated cost of service study and rate design for electric rates is evaluated by Mr. John Athas; and

(10) Gas Rate Design – Bruce Oliver: The Company's allocated cost of service study and rate design for gas rates is evaluated by Mr. Bruce Oliver.

3. POLICY OBJECTIVES AND VISION

Q. Please summarize what is under consideration in Docket 4770.

A. This docket, 4770, includes a proposal from Narragansett Electric Company for new rates to recover costs for the operating and capital expenses related to their basic function as a distribution company. In its filing, the Company seeks to enumerate and recover costs related to its core function.

Q. Please describe how trends in the electric distribution industry affect issues under consideration in this docket.

A. Since the Company's last general rate case in 2012 there are at least two major trends that have affected the functions of electric distribution utilities in all regions of the United States: first, the decline in costs for a renewable energy resources, including distributed photovoltaic, grid scale photovoltaic, onshore and offshore wind turbines and other distributed energy resources; and second, the decline in cost and increase in capability of a range of control technologies including sensors, communications, and software applications to provide near-real time remote visibility and automated control of the electric distribution system.

Q. How do these two trends relate to a distribution utility, such as Narragansett Electric Company?

A. These technology developments have changed the expectations among regulators and some customers of the kind of services the distribution utility may provide and the ways in which it can provide value to ratepayers. In Rhode Island, as in states across the United States, electric distribution utilities are now expected to integrate renewable energy resources and use information from customers and the distribution system to maintain reliability and manage system costs. That expectation is evidenced in Docket 4600 Stakeholder Report.[1] In particular, the report from stakeholders as well as the Guidance Document issued by the Commission identifies a series of attributes for the future electric system.

Q. Please describe recent legislative developments in Rhode Island that provide context for review of the Company's proposals in Docket 4770 and other dockets.

A. As the Commission is well aware, over the past fifteen years, Rhode Island has enacted energy policies that seek to increase fuel diversity, reduce costs, and promote clean energy. These measures include the 2006 Least-Cost Procurement Statute, which required the distribution utility to procure a range of cost-effective demand-side resources; the Long-Term Contracting Standard for Renewable Energy and the Renewable Energy Growth Program, which authorized the use of ratepayer funds to support and compensate the distribution utility for procurement of renewable energy resources; and the 2014

[1] *Report of Stakeholders in Docket 4600 to Rhode Island Public Utilities Commission.*

Resilient Rhode Island Act, which set economy-wide greenhouse gas emissions reduction targets to guide policy and regulatory decision-making.

Q. Please describe recent regulatory developments in Rhode Island that provide a context for review of the Company's proposal.

A. Building upon the legislative mandate of R.I. Gen. Laws § 39-26.6, the Commission convened stakeholders in Docket 4600 to inform an investigation into the changing electric distribution system. Together, stakeholders submitted to this Commission a report with goals to guide development of the future electric distribution system and the outlines of a Framework to guide cost-benefit analyses. Together, these regulatory and legislative changes represent over a decade of transformation of Rhode Island's power sector, as described in the November 2017 report Power Sector Transformation.

Q. How do these statutes and regulatory developments affect evaluation of the electric distribution utility?

A. Taken as a whole, Rhode Island's recent statutory changes present clear policy priorities: least-cost procurement, greenhouse gas emissions reduction, incorporation of clean energy, and resource diversification. Each of these priorities implicates a critical role for the electric distribution grid — through the need to manage an increasingly flexible set of demand resources; the need to electrify the thermal and transportation sectors; and the need to integrate growing numbers of diverse distributed energy resources (DER).

Q. In what way does this industry, legislative and regulatory context shape the Division's testimony in this Docket?

A. The utility has looked to existing legislative and regulatory direction to identify functions that are a part of the distribution utility's core business and which, therefore, necessarily fall within a review of the distribution utility's application for revised rates in this docket. This includes certain matters that are currently included in Docket 4780. In particular, the Division will include testimony related to the Company's rate of return that includes a proposal for revenue derived from performance incentive mechanisms. It is not in the interest of ratepayers to consider the underlying rate of return separately from a suite of proposed performance incentive mechanisms. Similarly, the Division will present testimony addressing the proposed advanced metering functionality study as it pertains to metering which is a core distribution business. Finally, the Division will present testimony related to a series of "grid modernization" proposals as they should not be considered separately from the distribution utility's core business. In contrast, there are other matters which the Division recognizes as significant components of transformation of Rhode Island's power sector that can be addressed either in this case or in Docket 4780.

Q. What is Power Sector Transformation and what is the Division's vision for how it should play out in Rhode Island?

A. As the Commission is well aware, Power Sector Transformation (PST) refers to a significant initiative to transform the electric distribution business that is regulated by the Commission in Rhode Island. The policy initiative is comprehensively set forth in a report to Governor Raimondo that has been posted through the Commission and

Division's website. It is entitled, *Rhode Island Power Sector Transformation - Phase One Report to Governor Gina M. Raimondo - November 2017* (PST Report). Rather than attaching the entire document to the testimony as an exhibit for a record that is already swimming in paper and PDF files, this is the link to the report: http://www.ripuc.org/utilityinfo/electric/PST%20Report_Nov_8.pdf

Instead of paraphrasing the reasons for Power Sector Transformation, we quote the first paragraph of the Executive Summary here:

> "The demands on Rhode Island's electric distribution system are rapidly evolving, driven by consumer choice, technological advancement and transformative information. The state's electric utility and regulatory framework were developed in an era in which demand for electricity consistently increased, technology changed incrementally, customers exerted little control over their electricity demand, electricity flowed one-way from the utility to customers, and the risks of climate change were unknown. Today, none of those factors is true: demand for electricity has plateaued; many customers generate their own power; electricity flows to and from customers; technologies are being introduced at rapid pace; and the need to mitigate and adapt to climate change is real. In these new circumstances, the traditional regulatory framework will not continue to serve the public interest. It will continue to push consumer prices upward without a corresponding increase in value for customers. This report presents recommendations to transform the power sector for these new circumstances and help control long term costs for consumers."[2]

Q. What are the goals of Power Sector Transformation?

A. The Power Sector Transformation initiative is ambitious. Consistent with Docket 4600, it has three overarching goals that are addressed in the PST Report: (1) control the long-

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[2] PST Report, p. 7..

term costs of the electric system; (2) give customers more energy choices and information; and (3) build a flexible grid to integrate more clean energy generation.

Q. What are the general categories of actions that are recommended for action to accomplish the goals?

A. The general categories of actions are summarized on pages 9 through 12 of the PST Report. They are (1) modernize the utility business model; (2) build a connected distribution grid; (3) leverage distribution system information to increase system efficiency; and (4) advance electrification that is beneficial to system efficiency and greenhouse gas emission reductions. The PST Report also summarizes on those pages numerous underlying actions. When reviewing the underlying actions, it is very clear that they are relevant to this rate case. For example, modernizing the utility business model includes such actions as creating multi-year rate plans, implementing performance-based ratemaking mechanisms, and addressing the issues associated with the tendency of utilities to favor rate base growth over other alternatives, among others. These are matters appropriate for consideration in the rate case. Similarly, the goal of building a connected distribution grid includes initiatives such as deploying advanced meters and focusing on capabilities to avoid technological obsolescence. The goal of leveraging distribution system information to increase efficiency also identifies the need to better align and integrate all the disjointed planning and cost recovery processes. This cannot be accomplished very effectively outside of the rate case. Finally, there are actions needed to address rate design, an area of ratemaking which occurs almost exclusively through rate cases.

Q. Is there an overarching principle implicit in advancing PST that is important to the Division?

A. Yes. In order for the utility business model to be truly transformed, new ways of managing and operating the distribution business as contemplated under Power Sector Transformation must become embedded within the business. PST should not be addressed, managed, and planned as if it is a special activity arising outside of the overarching management of the electric distribution system. It needs to be fully integrated into the core of the distribution business.

Q. What is the timeframe contemplated for accomplishing all of the PST goals?

A. The PST Report recognizes the degree of its own ambition when it states on page 12: "Transforming the power sector will not occur overnight." It is important to recognize because we are only at the beginning of a transformational process. It likely will take between three to six years to complete the transformation. But it will take even longer if we do not start in this rate case. It also could become problematic if the only means for the Company recovering the costs of the PST initiatives is a regulatory default to cost trackers. For reasons we will explain further, the Division believes it is extremely important that most, if not all, of the costs of the PST initiatives be recovered through base distribution rates as the initiatives unfold. Moreover, integration of grid modernization into the everyday business of the distribution utility will be slow in coming if it is not addressed in an integrated manner from a ratemaking perspective. This rate case is the critical first step in accomplishing the mission in a timely manner.

Q. Didn't the Commission separate the Power Sector Transformation initiatives from the rate case by establishing a companion Docket 4780?

A. Procedurally, there was a split. However, it has always been recognized that there is an unavoidable overlap between what is taking place to address the going-forward costs of the distribution business in the rate case with many of the initiatives that were proposed by the Company in its initial PST proposal which actually was filed with its general rate case. Even the Company recognized this in its response to Division Data Request 34-3, stating:

> "As a fundamental concept, Power Sector Transformation is arising as a focal point because of the need to make investments in the distribution system to meet changing requirements for electric service. Therefore, Power Sector Transformation is not an initiative that is unconnected to the provision of electric distribution service. Certain initiatives identified within Power Sector Transformation as necessary to enable modernization will directly, inevitably, and purposely be important to the provision of electric service over the next three years and beyond."

In fact, all the data requests and responses also have been filed in Docket 4780 have been filed in Docket 4770 as well. While it is appropriate for stakeholder engagement to continue in order to address the long-term vision of Power Sector Transformation, it is nevertheless essential to address some of the foundational initiatives in this rate case that will set base distribution rates for the Company to recover its costs of doing business for the rate year that spans from September 2018 through August 2019. While the single rate year establishes base rates for the distribution business using only a single year of projected costs, those rates will remain unchanged until the filing of the next rate case. For that reason, foundational PST planning should be integrated with and into the revenue requirement of the rate case in order to open the pathway to achieve the long-term goals of Power Sector Transformation that were detailed in the PST Report.

Q. Which features of the Power Sector Transformation program reflected in the PST Report does the Division believe will be important to address in this rate case?

A. There are at least four. They relate to performance-based incentives (PIMs), multi-year rate plans, certain foundational initiatives that need to commence now, and the AMI study needed to fully evaluate an AMI deployment.

Q. What does the Division see as important about the PIMs?

A. The Division believes performance-based incentive mechanisms should be a part of the outcome of this case. In order to transform the utility business model, more of the Company’s profit potential should be put at risk and reward. To do this effectively, earnings sharing and other parameters should be established around the allowed return when the return on equity is being set in the rate case. The Division is proposing not only a new set of PIMs, but also an earnings-sharing mechanism that takes into account the financial rewards arising out of other pre-existing incentives such as the energy efficiency program. A more detailed description of the Division’s proposal and reasoning is provided in the panel testimony sponsored by Melissa Whited and me elsewhere.

Q. What about multi-year rate plans?

The Division believes it is desirable for a multi-year rate plan to be negotiated for approval in this rate case. But even if one is not forthcoming, the Commission’s order should set the stage for the next rate case filing to be a multi-year plan. I will provide a deeper explanation of this in Section 5 of the testimony.

Q. What about the specific initiatives?

There are a number of the initiatives set forth in the Company's PST filing that the Division strongly believes should commence during the rate year and the costs included in the rate year revenue requirement in this case or in subsequent years of a multi-year plan. The most prominent initiatives relate to implementing the foundational GIS Enhancements during the rate year, expanding the System Data Portal project beyond the funding provided under the SRP, and commencing the DSCADA project sooner rather than later. We also will address this further in Section 5 of the testimony.

Q. What is the Division proposing regarding AMI?

Regarding AMI, the Division strongly believes the Commission should direct the Company to commence the AMI study as soon as possible and Rhode Island's fair share of the cost be included in the rate year revenue requirement as determined by Division witness Michael Ballaban. This too will be addressed in Section 5 of the testimony.

4. REGULATORY REVIEW AND COST RECOVERY

Q. Which proposals pending before the Commission in Docket 4780 are relevant to the rate case and recovery of the costs of the distribution business?

A. For reasons that we will explain, many of the proposals contained in the Company's original PST filing relate to the distribution business in a very fundamental and foundational way. As we already have mentioned, the Company also included a cost recovery mechanism that absolutely should be addressed in the context of this rate case. Further, the Division believes that some of the initiatives described by the Company as PST are not even properly categorized as Grid Modernization and should be a part of the distribution business that is reviewed in the context of the rate case on an integrated basis and the costs included in base distribution rates. In addition, the Division believes that the core Grid Modernization initiatives should become a part of the rate case review going forward. Unless the Commission addresses these issues in this docket, the opportunity would be lost to establish the right planning and cost recovery rules to effectively advance and change the way the distribution company conducts its business to take into account the fast-changing world of the electric utility industry and effectively meet the ambitious goals of Power Sector Transformation.

Q. Please summarize what the Company is asking the Commission to approve in Docket 4780, with regard to its power sector transformation initiatives.

A. In Docket 4780, the Company is asking the Commission to approve the following:[3]

- Approval of its proposed Power Sector Transformation Provisions. This includes (a) the methodology for calculating PST Factors and Reconciliation Factors; (b) the methodology for recovering PST performance incentives; and (c) the process for submitting annual PST Plans for review and approval by the Commission.

- Approval of $2 million for incremental costs for AMF design work in FY2019, Approval of a GIS Data Enhancement Project under a multi-jurisdictional scenario in light of the New York PSC's recent approval of the Company's affiliate's new rate plan in New York.[4]

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[3] Direct testimony of the National Grid Power Sector Transformation Panel, RIPUC Docket No. 4780, pp. 3-4.
[4] See the response to Division Data Request 32-23 in this Docket 4770.

- Approval of new PST performance incentive mechanisms.
- Findings regarding whether each proposed category of PST Plan investment is consistent with Rhode Island law, the Commission's Docket 4600 Guidance Document, and state regulatory policy, and whether such investments are appropriate for reimbursement as part of Power Sector Transformation.
- Findings regarding whether the proposed Power Sector Transformation incentive mechanism is consistent with Rhode Island law, the Commission's Docket 4600 Guidance Document, and state regulatory policy

Q. Please describe the changes that National Grid is recommending to the regulatory framework as it relates to the power sector transformation proposals.

A. National Grid is proposing that the Commission treat new PST-related investments differently from traditional, i.e., conventional, distribution system investments. The Company originally proposed the PST program in this docket. The Commission then asked the Company to refile in a separate docket 4780. But regardless of the procedural technicalities, the Company's proposal separates important distribution business activities from the rest of its integrated utility operations, moving away from an integrated long-term approach to running the distribution business to a stream of separate and siloed activities, the costs of which are recovered through a largely riskless rate recovery mechanism.

Q. How would cost recovery be altered by the Company's PST proposal?

Each rate case would set base distribution rates using a future, one-year test year, and those base rates would remain in place until the Company decides to file a new rate case.

In addition, the Infrastructure, Safety, and Reliability (ISR) process would continue to be used to recover the costs of relevant, conventional capital investments. The Company would file an ISR Plan each year for review and approval by the Commission for the next year's investments.

PST investments which may or may not be eligible for review under the ISR would be addressed on a multi-year basis with annual cost recovery filings.[5] The Company would file with the Commission an annual PST Plan that includes several years' worth of investments to reflect longer-term PST planning priorities, separately from the rest of its distribution business. The Commission would approve (a) the overall category of PST investments; (b) the proposed multi-year PST initiatives within each category; and (c) the actual PST investments for the forthcoming year for each of those initiatives.

PST investments would also be subject to a different cost recovery mechanism than applies to the base distribution business. National Grid proposes to establish a set of PST Factors to recover the forecasted capital costs and operations and maintenance (O&M) expenses for the forthcoming PST Plan Year. The Company would also establish a set of PST Reconciliation Factors to recover or credit any under- or over-recovery of the actual PST investments relative to the planned PST investments.[6] For purposes of the testimony, we refer to this mechanism as the proposed "PST Tracker."

During the annual review under the PST Tracker, the Commission would review historical PST investments to make sure the costs actually incurred were reasonable and

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5 Direct testimony of the PST Panel, p. 11, line 29.
6 Schedule PST-1, Chapter 10, p. 186.

prudent for cost recovery. The Commission would also review the forecasted PST investments for the forthcoming year. In that manner, the annual review under the PST Tracker would be very similar to the ISR process.

Q. Is the Company asking the Commission to pre-approve PST investments?

A. Yes. National Grid states that the PST Tracker would be the mechanism through which the Company seeks and obtains approval to make a particular investment.[7] Again, this essentially mirrors what is taking place under the ISR.

Q. What reasons does the Company provide for treating PST investments differently from conventional distribution system investments?

A. There are several reasons that the Company provides for its proposed regulatory framework. First, the Company asks for a fair opportunity to recover prudently-incurred cost, as well as revenue stability. The Company claims that without timely cost recovery it would not be able to meet the Commission's PST objectives.[8]

Second, the Company notes that there are statutory and other limitations regarding other potential funding mechanisms, such as the ISR, the energy efficiency (EE), and the system reliability planning (SRP) mechanisms.[9]

Third, the Company claims that stakeholder input regarding PST investments is critical, and that a general rate case does not allow for this type of input. National Grid claims that if it were to "move forward with these investments without critical feedback and input of

[7] Direct testimony of PST Panel, p.5, lines10-11.
[8] Direct Testimony of PST Panel, p.11, lines 29-32.
[9] Direct Testimony of PST Panel, p. 17, lines 3-18.

all interested participants, it would not be certain that its investments were appropriately meeting the needs of the state and its customers."[10]

Fourth, National Grid claims that, relative to recovery of costs through rate cases, its annual stakeholder process for reviewing PST investments "will provide concurrence and certainty about Power Sector Transformation investments before-hand, as opposed to after-the-fact, and result in more efficient and quicker progress to the next generation electric grid."[11]

Q. Do you have any concerns about the Company's proposed regulatory framework for PST investments?

A. Yes. There are very significant problems with the Company's approach that would have detrimental effects on the ability of the Division and the Commission to evaluate the distribution business activities of the Company on a logical, integrated basis. The cost recovery proposal shifts cost risks to ratepayers with little or no risk to the Company. It also would result in a spending/cost recovery cycle that would be difficult for the Division and the Commission to evaluate and control. Spending would lack needed discipline, with a very ineffective process to assure prudency.

Q. Please elaborate further on your concerns.

First, the Company's approach exacerbates the already fractured process for planning, reviewing, and approving utility investments.

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[10] PST Panel Direct Testimony, p. 18, lines 8-11.
[11] PST Panel Direct Testimony, p. 18, lines 11-14.

Second, the PST Tracker allows full reconciliation of the Company's PST initiative costs. This provides little incentive for the Company to contain those costs. In fact, what the Company is essentially proposing is the near equivalent to a new Commission-approved ISR process that pertains to the PST initiatives. While it is understandable from a utility shareholder point of view why the Company would want ISR-like tracker that provides recovery of all expenditures, this mechanism is not in the interest of ratepayers in the context of Power Sector Transformation.

Q. Are you implicitly suggesting that there also is a problem with the ISR mechanism?

A. No. Up to this point in the history of the ISR, the mechanism has worked effectively. With a few exceptions that the Division accepted and supported for unique reasons, the ISR process has typically been narrowly tailored to address the need for the utility to invest in the core utility system to assure the reliability and safety of the system. Because the ISR removes all regulatory lag between the time of investing and the time the costs are recovered for those investments, the mechanism encourages investment in an aging system and removes the tendency of the utility to defer needed investments in between rate cases because of short-term profit objectives.

The safeguard for ratepayers in the case of the ISR is that the Division plays a significant role in reviewing and agreeing to the capital spending plan up front. It is a very time-consuming process, but it has yielded benefits to ratepayers through the targeted investments. The Division has been comfortable with the process to date because the Division is an active participant in the capital planning approval process before the investment plan is filed. Because the ISR investments have tended to revolve around asset management of the traditional components of the distribution system, the program has been manageable and workable.

Q. Given recent success with the ISR, what is the problem with creating a similar mechanism through the PST Tracker?

Having acknowledged recent success of the ISR, however, it is still very important to point out that there are limits. To the extent the scope of a fully reconciling cost recovery mechanism expands to more and more business activities, the benefits begin to be outweighed by the detriments. First and foremost, a process that allows recovery of controllable costs through a tracker causes a shift of thinking in the utility. We believe it can cause the utility to pay much less attention to cost control, to the detriment of ratepayers who are ultimately paying for the whole program. The risks to the utility's shareholders are substantially reduced. As a consequence, the utility may develop the tendency to make investments even when there may be other alternatives because the risk of cost recovery being denied are minimal and the process allows a smooth path to growth in the rate base, an outcome which is not always in the ratepayers' best interest.

Q. Isn't there a safeguard built into the process that allows after-the-fact review of the project expenditures?

A. Theoretically, yes. But the reality is that the utility is in the driver's seat. In Rhode Island, the Division is simply not staffed or funded to do a deep dive review of every project to assure that all the ratepayer dollars were prudently spent. For that reason, only in cases where the negligent management of a project is readily apparent does the after-the-fact review provide a practical means of recourse. When the scope of the projects is narrow and straightforward, like the typical projects that are reviewed in the ISR, the process is manageable. But once the scope expands to projects that are highly complex, with very sophisticated IT and other systems involved, the protections to ratepayers become more theoretical than real. Trying to perform a *post hoc* review of project management and expenditure planning on complex systems projects is extremely challenging, especially for a jurisdiction like Rhode Island where personnel resources are constrained.

Q. Are you suggesting the Commission try to alter the ISR?

A. No. The ISR is a statutory mechanism. Because it is statutory, it limits the Commission's authority to alter it. The Division still believes that the ISR continues to provide benefits in a process that has worked effectively. We are only using the ISR as an example to illustrate the risks to ratepayers if a similar mechanism is adopted for parts of the distribution business that do not fall neatly into the eligibility categories for the ISR. That is one of the core problems with the Company's PST Tracker proposal.

Q. In light of the problems you have identified with the PST planning and PST Tracker, what is the Division proposing in its place?

A. The Division believes it is inappropriate and detrimental to ratepayers for most of the initiatives set forth in the Company's PST proposal to be reviewed and addressed outside of a rate case. We will elaborate further in the testimony on this point when we discuss the need for multi-year rate plans, through which a comprehensive, integrated multi-year business plan can be fully evaluated. Further, as explained in the testimony of Division witness Greg Booth, the Company has chosen how to define activities that are grid modernization for inclusion in its proposed PST cost tracker. In that context, the Company has defined it too broadly. Specifically, there are at least two significant initiatives that are not Grid Modernization at all. They are initiatives that the Company should be undertaking as a regular part of its distribution business.

Q. Is there other information that supports the premise that cost recovery for initiatives that modernize the grid should occur through base rates?

A. Yes. The practices of National Grid across jurisdictions is a good example. In Division Data Request 24-12, the Division asked the Company the following data request:

> "Has any of National Grid's electric distribution affiliates in Massachusetts and New York undertaken or completed any significant initiatives or projects over the last five years to modernize the distribution system (other than the Worcester pilot and Clifton Park demonstration projects)? If so, please identify and describe the initiatives or projects undertaken over that period."

In response, the Company identified numerous projects. After seeing the list, the Division asked a follow-up data request as follows in Division 32-53:

> "Referring to the response to DIV 24-12, for each of the initiatives identified in the response, please indicate whether there were any special rate recovery mechanisms (outside of base distribution rates) used to recover the costs of the initiative, describe how the special rate recovery mechanism operates, and indicate whether it is a fully reconciling tracker similar to the one proposed in Docket 4780 that allows recovery of O&M and capital costs whether the they exceed original estimates or not."

Q. Did the Company's answer reveal anything important?

A. Yes. Of the 20 initiatives identified, only 2 projects actually had costs recovered from a two-way tracker. One was a demand response initiative, the costs of which apparently flow through an applicable energy efficiency program tracker. The only other related to utility-owned solar projects in Massachusetts. No other projects operated like the PST

Tracker proposed in Rhode Island. The response identifies only 4 other projects where costs are tracked. But these projects arose in the context of the New York REV proceeding, which deferred cost recovery and capped total expenditures at $44 million for a selection of REV activities. It appears that the Company's affiliate has the right to file a petition to request higher recovery if the utility exceeds the budget, but it is not guaranteed. All of the 14 remaining projects on the list were not recovered through a tracker at all, with 11 of those projects specifically recovered through base distribution rates.

Q. Do any of the projects being recovered through base distribution rates address activities similar to what the Company proposed in Docket 4780?

A. Yes. The System Data Portal project, an Advanced Data Analytics project, a Hosting Capacity Analysis relating to distributed generation interconnections, a Remote Terminal Unit (RTU) project, a Data Management System (DMS) pilot project, an energy storage demonstration project, automating field devices, installing feeder monitoring sensors, and implementing some telecommunications upgrades relating to reclosers on the distribution system.

Q. Does the Company explain why inclusion of these projects in base distribution rates was possible?

A. Yes. The Company points out that there was a three-year multi-year rate plan, stating: "Note that base distribution rates for Niagara Mohawk Power Corporation (NMPC), the Company's affiliate in upstate New York, are based on a three-year forward looking rate case, so proposed revenue requirements are approved in addition to historic additions to rate base, O&M costs are adjusted to include known and measurable impacts to the test year O&M." Ironically, this is the type of ratemaking the Division is advocating in this rate case for addressing the recovery of costs in the future over several years, rather than setting rates for one year at a time or adopting the fully reconciling PST Tracker proposed by the Company in Docket 4780.

Q. Which initiatives has Mr. Booth identified as ones that should be undertaken by the Company as a part of its traditional distribution business?

A. As Mr. Booth explains, the GIS Enhancements and the DSCADA program, each of which is discussed in Chapter 3 of PST-1 that was originally filed in this docket, are initiatives that the Company should be implementing as a part of its prudent operation of the distribution business. For that reason, the Division proposes the Company move forward immediately with the GIS Enhancements and begin to take steps for DSCADA implementation. Division witness Michael Ballaban will address the Division's proposal on how the costs of the GIS Enhancements should be reflected in the revenue requirement for the rate year. It is not clear whether the DSCADA program is ready for advancement in the rate year, but the Division believes the Company should be undertaking the project without delay by no later than calendar year 2020. The Company should then seek recovery of the costs of the DSCADA by filing for rate relief through the rate case process, but the Division does not believe it is appropriate to establish a special cost tracker for the cost recovery outside of a rate case.

Q. What about the Company's proposal for the System Data Portal?

A. The Division supports the implementation of the System Data Portal project. The project has already been partially funded through the SRP. But the Company has not proposed to move forward more completely yet. Like its other PST projects, the Company proposes the additional costs of the System Data Portal project be recovered through its proposed PST Tracker. The Division, of course, opposes that means of recovery. Instead, the Division recommends that the annual costs associated with moving forward with the System Data Portal project be included in the rate year revenue requirement. There are no incremental capital costs and even the Company has conceded that there is no practical impediment to recovery of the costs through base rates in this rate case. (See the response to Division 27-11.) According to the Company, the going forward costs are only operation and maintenance costs associated with time spent by engineers on the portal.

Q. Does the Division agree with the Company's annual cost estimate for the System Data Portal?

A. No. As Division witness Greg Booth testifies, the proposal to fund three engineers appears excessive. For that reason, the Division proposes to reduce the request by one third. The Division's revenue requirement witness, Michael Ballaban, has reduced the annual cost by 30 percent in the rate year revenue requirement.

Q. What about the Company's proposal to perform an AMI study?

A. The Division believes the Company should perform the study. We will discuss the reasons further in the testimony elsewhere in separate testimony sponsored by Melissa Whited and me. However, the Division disagrees with the Company's estimate and allocation of the cost of the AMI study chargeable to Rhode Island, as described in the testimony of Division witness Michael Ballaban. The Division proposes that the study go forward, subject to the cost recovery adjustments recommended by Mr. Ballaban for the rate year. As Mr. Ballaban explains, the Company estimated a cost to Rhode Island for a combined study with New York at $2 million. However, for the reasons explained by

Mr. Ballaban, the Division believes the Company's estimate is not reasonable and lacks a defensible foundation. Mr. Ballaban explains why the rate allowance funded by Rhode Island should be $1 million, which should be amortized over three years.

Q. Are there any other actions the Company should be taking in connection with grid modernization?

A. Yes. Consistent with the testimony of Division witness Greg Booth, the Division recommends that the Company be directed to complete a comprehensive grid modernization plan (GMP) that is developed in sync with the AMI Study. The plan should be developed with stakeholder input and could take place under the umbrella of Docket 4780 or in a separate Docket. But the GMP should be filed with the Commission around the same time as the AMI Study, to allow AMI deployment and the GMP to be considered together.

Q. How do performance incentive mechanisms fit into the Division's proposed regulatory framework?

A. The Division is proposing a set of PIMs that are an important element in the regulatory framework. These PIMs provide additional sources of revenues and thus utility management incentives to implement some of the PST initiatives and achieve some of the PST goals. These performance incentive mechanisms are directly connected with consideration of the company's rate of return in this docket. These PIMs are discussed in more detail in separate testimony sponsored by me and Melissa Whited.

5. MULTI-YEAR RATE PLANS

Q. Why does the Division support the concept of multi-year rate plans?

A. One of the most important reasons is that a multi-year plan requires and facilitates planning over a multi-year horizon on a fully integrated basis. In the context of Power Sector Transformation, planning needs to take place with multiple years in view, relating the activities to the core distribution business. For that reason alone, implementing a multi-year plan is highly preferable. But there also is another important benefit. The multi-year rate plan not only provides the most effective way to advance the very important multi-year transformative initiatives, it also addresses in a balanced manner the tension relating to cost recovery that often exists between the competing interests of ratepayers and shareholders.

Q. What are the ratepayer interests in this context?

A. The most important is the obvious interest in protecting ratepayers from unreasonable rates, including rate stability. In addition, there is the interest of advancing important public policies that need the utility to make significant investments with cost discipline. This interest is now becoming more important than ever as policymakers look to advance important transformational initiatives relating to climate change, an evolving distribution system, and accommodation of a distribution system with distributed resources.

Q. What is the interest of the utility in this context?

A. The interest of the utility is straightforward and not surprising. In providing service to consumers, utilities incur costs. In past decades, costs could be more easily recovered by sales growth and other factors that increased usage which, in turn, increased revenues to cover on-going costs and investments. In recent years usage on the electric side of the business is either flat or declining. Revenue decoupling helps stabilize the revenue stream for the distribution utility, but it does not provide additional revenue in between rate cases to provide the necessary financial signals for the utility to invest. In fact, we believe this is the primary reason for the passage of the statute establishing the ISR. It also is self-evident from the fact that it is embedded in the revenue decoupling section of the law. The electric system was aging, yet the Company did not have the revenue stream to invest without depleting its earnings in between rate cases. By creating the ISR at the same time as implementing decoupling, conventional investments were facilitated and service quality vastly improved while energy efficiency goals were being achieved. There may have been other ways to address this issue, but Rhode Island policymakers chose the ISR mechanism.

If we were on a path of business as usual, there might not be a need for a change. But that is not the state of the industry. As mentioned earlier, policymakers acting on behalf of customers desire transformational changes in the utility business to advance important goals. But these initiatives require a longer-term investment vision that utilizes multi-year investment plans. Phasing-in of significant projects is likely to become more important over the next decade. The "one-year-at-a-time" ISR is not adequate, even if the investments are eligible under the statute. The Company in this case acknowledges that a large infusion of investments is needed to transform the power industry. But it is reluctant to advance the programs unless it has assurance of cost recovery without any regulatory lag or significant risk.

Q. Couldn't the Commission simply order the Company to implement the initiatives and address cost recovery in their next rate case?

A. Yes. The Commission, like other state commissions across the country, always has the option to issue mandates for utilities to take certain actions or implement initiatives, while addressing cost recovery in subsequent rate cases. It may be that the Commission would need to resort to such action in Rhode Island. However, while the Commission could assert its authority aggressively to simply order the Company to implement programs without addressing how the costs will be recovered until the next rate case, taking such action means the utility implements under regulatory duress. On the surface it may appear effective, but too often risk averse, financially-influenced inertia can slow or halt real progress behind the scenes. Many regulatory mandates can be effective and are necessary. But the types of initiatives being contemplated here are intended to be transformational. In order for the transformation to be effectively accomplished, it is preferable to address it in a manner that works for all parties concerned.

Q. How has the Company proposed to address its interest to recover the costs in a timely manner?

A. The Company has proposed a fully reconciling PST Tracker. The tracker would undoubtedly address the Company's interest in the most ideal manner from the Company's perspective. In such case, the Company would obtain up-front approval. The approval would allow it to spend money on the initiative with no concerns about earnings impacts because the Company would be virtually guaranteed to get all its money back from the spending, with a formulaic return on its investment.

Q. But would that be a balanced approach that is fair to ratepayers?

A. No. The Company's proposal does not address the interests of ratepayers who should be assured that the utility is operating efficiently at reasonable cost. From the ratepayers' perspective, there needs to be some financial pressure created to assure the utility experiences real consequences for any lack of discipline in spending.

Q. What about the Company's claim that without timely cost recovery it would not be able to meet the Commission's PST objectives?

A. This claim assumes that the Company's capability to implement an initiative is obstructed unless the Company gets its money first or at least a guarantee for later. In the history of ratemaking, this has never been the general rule. In fact, it has typically been the opposite. Rates have been set for one year and the Company exercises its duty to maintain safe and reliable service with the revenue obtained by the rates in effect. The reconciliation of some of the ordinary business expenses and cost of capital is the exception. Currently, only 15% of annual electric distribution-related revenue is recovered through reconciling mechanisms. (See the response to PUC 3-9, Attachment 3-9, page 1 of 2, line 3) The idea that absent a fully reconciling cost recovery mechanism the Company cannot do its job or run the business not only lacks credibility, but flies in the face of ordinary principles of ratemaking. Timely recovery undoubtedly makes it much easier for the Company to maintain higher earnings while carrying out its responsibilities. However, while factors such as regulatory lag or lack of dollar-for-dollar precision between revenues and costs may cause some earnings instability, they would not, as a practical matter, prevent the Company from meeting the PST objectives.

Q. What is the Division's proposal for a balanced and effective solution?

A. The balanced and most effective solution that is consistent with the Division's vision for advancing the "utility of the future" is the concept of multi-year rate plans. There is nothing new in the industry about such plans. They have been implemented in many places. But in recent years, they have not been utilized in Rhode Island. Given the needs and interests already identified, it is the most balanced answer that is fair to all participants.

Q. What are the key features of a multi-year rate plan?

A. First, the Company should be required to file a multi-year business plan with granular and reliable forecasts of costs for each year of the plan, including any forecasted costs relating to grid modernization and AMI. This would allow all parties to examine the direction in which the utility is planning to move. It also would allow for significant stakeholders and regulatory input in a comprehensive and integrated way. Most of the utility's distribution business activities that are funded on the delivery side of the bill would be available for comprehensive review. To the extent there is a need to advance transformational, multi-year initiatives that can only be accomplished by phasing in investments across several years, the multi-year rate plan is ideal. A budget for the activities can be established, the base distribution rates can be set to match the budget, and the utility can be launched to achieve the goals. But unlike a mechanism that reconciles costs, this type of planning and cost recovery provides better signals to the utility. Instead of the utility falling into financially-neutral spending patterns because it is ratepayer money it is using under a reconciliation, the utility will experience the budget as its own money at risk. That is, if the utility achieves the objectives under budget, the utility is rewarded. Conversely, if the utility mismanages and exceeds the budget, the utility's earnings suffer.

Q. Why is this fair to all participants?

A. If it is properly designed, the multi-year rate plan is fair to ratepayers because it caps targeted spending at pre-determined reasonable levels. It also should be desirable to policymakers because it advances the desired initiatives. Finally, it is fair to the utility because it provides a reasonable opportunity for the utility to recover all of its costs of the initiatives in a timely manner, while achieving a reasonable return for its shareholders. Surely, the Company should have no legitimate complaint if it has a realistic opportunity to recover its prudently-incurred costs, but has to accept the ordinary risks of running the utility business along the way, including budget discipline.

Q. What about allowing time for stakeholder input?

A. Stakeholder input will continue to be important. Rhode Island has already recognized this when it launched its Power Sector Transformation initiative. Numerous technical sessions have been held. Other sessions have been held in the context of the companion docket to this rate case, Docket 4780. But this is only the first step. A multi-year rate plan requirement does not preclude further stakeholder sessions.

Q. The Company maintains that a PST Tracker is needed because of stakeholder input. What is your view?

A. One of the main reasons given by the Company for a PST Tracker is that they want stakeholder input that could affect costs. But stakeholder input and planning are not dependent upon the Company getting fully-reconciled cost recovery. Reconciliations should be the exception, not the rule. Effective stakeholder input is achieved through engagement, not assurances of cost recovery with no regulatory lag. It is the Company's role and responsibility to invest in the initiatives that are prudent and support their request for recovery with results.

Q. How long should the multi-year rate plan be?

A. The number of years should be at least three. This gives the utility two years of operating under the budgets before it needs to file for another multi-year plan. During year three, it operates under the third year's budget while the next plan is negotiated or litigated. It is possible that a plan that runs five years could work. But when there are new initiatives never experienced before, three years is a better place to start. Otherwise, technology and the industry can advance ahead, leaving policymakers and the Company behind.

Q. What is needed in the filing for financial data?

A. It is critical that the Company file a comprehensive revenue requirement for each year of the Rate Plan. This needs to be for more than just one rate year. It should reflect a real plan of spending that can be justified in a granular manner, not mere inflationary adjustments off the first year of projected costs. The filing should also include projections for three years of capital spending for capital projects that are both eligible and not eligible under the ISR. This would allow the Division, the Commission, and other intervenors to evaluate the overall plan on an integrated basis.

Q. What about projects and costs associated with "grid modernization"?

A. The three-year business plan should also provide an integrated plan to advance the goals of modernizing the grid. The objectives should be clear and there should be a transparent way to evaluate how well multiple initiatives relate to each other.

Q. Why would a capital plan for the three years be important, given the existence of the ISR?

A. The ISR provides review of plans that proceed one year at a time. While the Company has provided multi-year forecasts, the focus is on the upcoming year. This can result in skewed, short-term vision. The full plan of capital spending on the conventional investments eligible for the ISR should be included along with the other investments and spending for the transformational programs that need multi-year schedules. Annual cost recovery for ISR-eligible projects would continue to be addressed in the annual ISR process. The ISR planning process would be effectively embedded within and function in parallel with the multi-year plan. However, all capital projects that are not otherwise eligible for ISR treatment would be addressed in a parallel capital budget. In this way, all capital spending over the three-year period would be addressed together.

Q. Given the fact that the ISR is fully reconciling, how would the multi-year rate plan address the concern that it does not result in a binding spending budget?

A. This can be resolved through a capital efficiency incentive. There may be several different ways to design an incentive that works in tandem with the ISR and the multi-year plan. But the Division is considering a specific framework that would create spending discipline.

Q. How would the capital spending efficiency incentive operate?

A. First, the Company would provide a three-year capital spending plan for all ISR eligible projects for which it anticipates seeking approval under the ISR. This would be reviewed and provisionally approved by the Commission. The spending budget would then be tracked for the three years of the plan. The Division envisions a cumulative spending budget in the aggregate. At the end of the three years, the three-year spending as it actually occurred under the ISR is compared to the budget approved by the Commission when approving the multi-year plan. To the extent the Company has achieved its objective under the aggregate budget, savings can be kept or shared with ratepayers. However, if the Company has exceeded the aggregate budget in circumstances where no approved exceptions apply, the Company would be required to refund customers an amount equal to the incremental increase in the revenue requirement during the rate plan that was caused by the overspend.

Q. How does it affect the Company's cost recovery after the plan is over?

A. The Company would still be able to include the capital costs in rate base in the future, provided that the spending was prudent, but it will have suffered the equivalent of a one-year regulatory lag in partial cost recovery for missing the aggregate three-year budget target, as measured at the end of the plan. This achieves a result which creates a virtual budget for the three years, yet it does not affect the operation of the ISR under the statute. There is no prohibition against exceeding the budget. Rather, it is simply an incentive mechanism with a reward or penalty determined at the end of the rate plan period. As a result, it provides spending discipline that does not currently exist without the multi-year plan. It does not preclude the Company from doing what it needs to do to provide safe and reliable service. The penalty would be financially analogous to creating a one or two-year regulatory lag on a portion of the Company's capital cost recovery that exceeds the budget. It would be similar to what happens across the country for utilities that make investments in one year, but do not obtain additional rate relief until the next rate case after the projects are in service.

Q. What about the PST initiatives?

A. As explained earlier, the rate case filing would contain spending forecasts for any proposed PST initiatives. A budget would be created for each year of the plan, including allowances to cover approved expenses for the initiatives. The Company would then need to implement the initiative within the approved budget. Incentives also could be included, but the basic effect is to require the Company to operate with spending discipline, knowing that excess costs will not be fully reconcilable. Some modifications and exceptions could be included for more complex initiatives, but the basic objective of creating a budget and spending discipline would be addressed. In effect, the goal would be to have the costs of the PST initiatives recovered through base distribution rates rather than a tracker.

Q. Are there any other features that would be included in a multi-year rate plan?

A. We would expect so if a plan is negotiated in this rate case. For example, a multi-year rate plan is flexible enough to incorporate any consensus items that may emerge from discussion among parties in Docket 4780 over the next three months, such as electric transportation, electric heat and energy storage. In addition, we anticipate that a multi-year rate plan negotiated as a part of this docket could have an explicit re-opener for AMI investments that we recommend the Commission address following submittal of the

Company's proposed AMI study. What we have explained here may not be the only way to achieve the balance of interests. But it illustrates the parameters of how it can be done. In the end, the Division is adamant that the proposed PST Tracker is not in customers interests and should not be approved by the Commission.

Q. Is it possible for a multi-year rate plan to be implemented as a result of this case?

A. Yes. But the Division believes the only practical way that an effective multi-year rate plan can emerge from this rate case is through a negotiated settlement. The reason is because the Company filed its case under the old set of assumptions about one-year ratemaking. While the Company initially included its PST proposals and provided some multi-year data, the current state of the case makes it very difficult for the Commission to order an effective three-year rate-setting outcome. The best result would be a negotiated solution that involves the Company working with the Division and others to address the many complexities. The Division believes this is possible, even with some of the shortcomings present in the Company's current filings. It could be an important first step toward a future ratemaking process.

6. RATEMAKING RECOMMENDATION FOR THIS DOCKET IF THERE IS NO MULTI-YEAR RATE PLAN

Q. How should the Commission treat PST and other investments in this docket if there is no multi-year rate plan settlement?

A. To the extent a multi-year rate plan settlement cannot be negotiated and filed with the Commission for approval, the Commission is left with a one-year rate case that sets rates for the rate year only. This case, however, still presents an opportunity to set a course for the future, beginning with clear and unequivocal directives that the Commission should give to the Company in this case, combined with approval of some of the initiatives that can be carved out of the Company's PST proposal and embedded into the rate year revenue requirement. The Commission also should establish new performance-based incentive mechanisms to begin sending effective financial signals to the Company as we move into the transformation of the industry. We will discuss the Division's PIMs proposal in the separate testimony of Melissa Whited and me.

Q. How should the Commission proceed if there is no multi-year plan?

A. First, in the absence of a multi-year rate plan, the Commission should set rates for the rate year, without a new PST Tracker as proposed by the Company. In doing so, the Commission should make it clear to the Company that recovery of non-eligible ISR costs relating to all the PST initiatives is not favored. The Commission should establish the principle that recovery of the costs of most PST initiatives should typically be addressed in rate cases that set forth an integrated, multi-year plan. The Commission should leave room to make exceptions as it deems sensible. But the initiatives should not be addressed in special rate reconciliation processes that isolate those programs from the rest of the distribution business. This would not preclude technical sessions related to major initiatives that would benefit from Commission review and stakeholder participation, but such technical processes should not be a process for obtaining rate recovery through special mechanisms. They should be an evaluation of the details, benefits, and desirability of integrated initiatives.

Second, the Commission should require the Company to move forward with the GIS Enhancements, the AMI Study, and the System Data Portal commencing in the rate year, with the costs recommended by the Division included in the revenue requirement.

Third, the Commission should establish new performance based ratemaking incentives that work in tandem with the Company's return on equity allowance. As mentioned, we will address this proposal in greater detail in the direct testimony sponsored by me and Ms. Whited.

Finally, the Company should be directed to develop a comprehensive, integrated plan for Grid Modernization that builds upon the initiatives that are recommended by witness Greg Booth for the rate year. This plan, in turn, should be filed with the Commission as a part of a multi-year rate case that includes an integrated business plan with three years of revenue requirement data that allows a complete and thorough review of the costs forecasted for each year of the plan, including all of the costs of the distribution business not otherwise governed by statutory requirements, such as the ISR. As a component of the plan, new initiatives can be included that provide the opportunity to the Company for recovery of the costs through base rates in each year of the plan. The Commission should place a deadline on the Company for the filing of the multi-year plan no later than the first half of 2020 for new rates to take effect no later than the first quarter of 2021. This schedule will allow enough time for planning and continued stakeholder input on the PST and Grid Modernization initiatives, including AMI.

Once the first multi-year rate plan is in place, the Company can be placed on a three-year schedule going forward. During the interim, however, the Commission must be clear that the company should be undertaking any projects it believes are prudent and cost-effective, whether conventional or PST.

Q. Does the Division believe the Commission has the authority to require a multi-year rate plan by a specified date?

Yes. Absolutely. While the Company traditionally has been left with the discretion to commence rate cases on its own schedule, this has been by default or regulatory tradition. There are no statutory provisions or other legal requirements of which we have been made aware that create a limitation or requirement that precludes such an action. The Division believes the Commission has broad supervisory authority over the rates of the utility that permits it to investigate rates and require rate filings relating to the costs of the business.

Q. How should the Commission address AMI?

A. The Commission should direct the Company to complete the AMI study and file it with the Commission for review prior to implementation. As described elsewhere in the testimony, the costs of the study should be addressed in the rate year of this rate case, as recommended by the Division in the testimony of Mr. Ballaban. If deployment is ultimately approved by the Commission, the costs of deployment should be included in base rates as a part of the multi-year rate plan filing made during the first half of 2020. But implementation should not be delayed in order for the means of cost recovery to be engraved in regulatory stone before the Company advances prudent programs. As the Division's witness Ballaban testifies, National Grid did not wait for all regulatory cost approvals to be in place before launching the Gas Business Enablement program that achieved higher proportional benefits to New York than Rhode Island. The program was launched and the costs allocated to all jurisdictions. Likewise, it should not wait for favorable cost recovery to be approved in all other jurisdictions to be in place before beginning the process in Rhode Island, should the Commission find deployment of AMI appropriate and prudent.

Q. Are there any particular components that the Division considers important to include in the AMI study?

A. Yes. The Division has identified two distinct opportunities to significantly reduce the potential cost of AMI deployment for ratepayers: alternative ownership models for meter infrastructure and shared communications systems. While deployment of AMI without either of these innovative approaches may still provide ratepayers greater benefits than costs, the Division argues the AMI study should examine each of them. In addition, the Division will request that it be involved in regular monthly meetings on the study process.

Q. Does the Division's case in this docket address the Company's proposed electric transportation, electric heat or energy storage initiatives?

A. No. However, as described in the November 2017 Power Sector Transformation Phase I Report, the Division understands that electric transportation, electric heat and energy storage are important components of a transformed power system and advance key attributes of the electric power system codified in Docket 4600, such as addressing climate change. Because of the decision to separate Docket 4770 and 4780, these topics are currently under review in Docket 4780. The Division anticipates submitting its testimony on these matters in Docket 4780 in two weeks. The Division further anticipates that a settlement among parties in this docket may include versions of the electric transportation, electric heat and energy storage programs currently proposed in Docket 4780.

Q. Does this conclude your testimony?

A. Yes.

AFFIDAVIT OF TIM WOOLF

Tim Woolf, does hereby depose and say as follows:

I, Tim Woolf, on behalf of the Rhode Island Division of Public Utilities and Carriers, certify that testimony that bears my name was prepared by me or under my supervision and is true and accurate to the best of my knowledge and belief.

Signed under the penalties of perjury this the 6th day of April, 2018.

Tim Woolf
Tim Woolf (Apr 5, 2018)
____

Tim Woolf

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PROFESSIONAL EXPERIENCE

Synapse Energy Economics Inc., Cambridge, MA. *Vice President*, 2011 – present.

Provides expert consulting on the economic, regulatory, consumer, environmental, and public policy implications of the electricity and gas industries. The primary focus of work includes technical and economic analyses, electric power system planning, climate change strategies, energy efficiency programs and policies, renewable resources and related policies, power plant performance and economics, air quality, and many related aspects of consumer and environmental protection.

Massachusetts Department of Public Utilities, Boston, MA. *Commissioner*, 2007 – 2011.

Oversaw a significant expansion of clean energy policies as a consequence of the Massachusetts Green Communities Act, including an aggressive expansion of ratepayer-funded energy efficiency programs; the implementation of decoupled rates for electric and gas companies; an update of the DPU energy efficiency guidelines; the promulgation of net metering regulations; review of smart grid pilot programs; and review of long-term contracts for renewable power. Oversaw six rate case proceedings for Massachusetts electric and gas companies. Played an influential role in the development of price responsive demand proposals for the New England wholesale energy market. Served as President of the New England Conference of Public Utility Commissioners from 2009-2010. Served as board member on the Energy Facilities Siting Board from 2007-2010. Served as co-chair of the Steering Committee for the Northeast Energy Efficiency Partnership's Regional Evaluation, Measurement and Verification Forum.

Synapse Energy Economics Inc., Cambridge, MA. *Vice President*, 1997 – 2007.

Tellus Institute, Boston, MA. *Senior Scientist, Manager of Electricity Program*, 1992 – 1997.

Association for the Conservation of Energy, London, England. *Research Director*, 1991 – 1992.

Massachusetts Department of Public Utilities, Boston, MA. *Staff Economist*, 1989 – 1990.

Massachusetts Office of Energy Resources, Boston, MA. *Policy Analyst*, 1987 – 1989.

Energy Systems Research Group, Boston, MA. *Research Associate*, 1983 – 1987.

Union of Concerned Scientists, Cambridge, MA. *Energy Analyst*, 1982-1983.

EDUCATION

Boston University, Boston, MA
Master of Business Administration, 1993

London School of Economics, London, England
Diploma, Economics, 1991

Tufts University, Medford, MA
Bachelor of Science in Mechanical Engineering, 1982

Tufts University, Medford, MA
Bachelor of Arts in English, 1982

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TESTIMONY

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New York Public Service Commission (Case 17-E-0459): Direct testimony of Tim Woolf regarding Energy Efficiency Earnings Adjustment Mechanisms proposed by Central Hudson Gas & Electric Company. On behalf of Natural Resources Defense Council. November 21, 2017.

New York Public Service Commission (Case 17-E-0238): Direct and rebuttal testimony of Tim Woolf and Melissa Whited regarding Earnings Adjustment Mechanisms proposed by National Grid. On behalf of Advanced Energy Economy Institute. August 25 and September 15, 2017.

Utah Public Service Commission (Docket No. 14-035-114): Direct and rebuttal testimony of Tim Woolf regarding the Pacificorp's analysis of the benefits and costs associated with distributed generation resources. On behalf of Utah Clean Energy. June 8, 2017 and July 25, 2017.

Massachusetts Department of Public Utilities (D.P.U. 17-05): Direct and surrebuttal testimony of Tim Woolf and Melissa Whited regarding performance-based regulation, the monthly minimum reliability contribution, storage pilots, and rate design in Eversource's petition for approval of rate increases and a performance-based ratemaking mechanism. On behalf of Sunrun and the Energy Freedom Coalition of America, LLC. April 28, 2017 and May 26, 2017.

Massachusetts Department of Public Utilities (D.P.U. 15-120, D.P.U. 15-121, D.P.U. 15-122/15-123): Direct testimony of Tim Woolf and Ariel Horowitz, PhD, regarding the petitions by National Grid, Unitil, NSTAR, and Eversource Energy for approval of their grid modernization plans. On behalf of Conservation Law Foundation. March 10, 2017.

Massachusetts Department of Public (D.P.U. 16-169): Direct testimony of Tim Woolf and Erin Malone regarding Nation Grid's petition for ruling regarding the provision of gas energy efficiency services. On behalf of the Cape Light Compact. November 2, 2016.

New Jersey Board of Public Utilities (Docket No. ER16060524): Direct testimony regarding Rockland Electric Company's proposed advanced metering program. On behalf of the New Jersey Division of Rate Counsel. September 9, 2016.

Colorado Public Utilities Commission (Proceeding No. 16AL-0048E): Answer testimony regarding Public Service Company of Colorado's rate design proposal. On behalf of Energy Outreach Colorado. June 6, 2016.

Georgia Public Service Commission (Docket No. 40161 and Docket No. 40162): Direct testimony regarding the demand-side management programs proposed by Georgia Power Company in its Certification, Decertification, and Amended Demand-Side Management Plan and its 2016 Integrated Resource Plan. On behalf of Sierra Club. May 3, 2016.

Massachusetts Department of Public Utilities (Docket No. 15-155): Joint direct and rebuttal testimony with M. Whited regarding National Grid's rate design proposal. On behalf of Energy Freedom Coalition of America, LLC. March 18, 2016 and April 28, 2016.

Maine Public Utilities Commission (Docket No. 2015-00175): Direct testimony on Efficiency Maine Trust's petition for approval of the Triennial Plan for Fiscal Years 2017-2019. On behalf of the Natural Resources Council of Maine and the Conservation Law Foundation. February 17, 2016.

Nevada Public Utilities Commission (Docket Nos. 15-07041 and 15-07042): Direct testimony on NV Energy's application for approval of a cost of service study and net metering tariffs. On behalf of The Alliance for Solar Choice. October 27, 2015.

New Jersey Board of Public Utilities (Docket No. ER14030250): Direct testimony on Rockland Electric Company's petition for investments in advanced metering infrastructure. On behalf of the New Jersey Division of Rate Counsel. September 4, 2015.

Utah Public Service Commission (Docket No. 14-035-114): Direct, rebuttal, and surrebuttal testimony on the benefit-cost framework for net energy metering. On behalf of Utah Clean Energy, the Alliance for Solar Choice, and Sierra Club. July 30, 2015, September 9, 2015, and September 29, 2015.

Nova Scotia Utility and Review Board (Matter No. M06733): Direct testimony on EfficiencyOne's 2016-2018 demand-side management plan. On behalf of the Nova Scotia Utility and Review Board. June 2, 2015.

Missouri Public Service Commission (Case No. ER-2014-0370): Direct and surrebuttal testimony on the topic of Kansas City Power and Light's rate design proposal. On behalf of Sierra Club. April 16, 2015 and June 5, 2015.

Missouri Public Service Commission (File No. EO-2015-0055): Rebuttal and surrebuttal testimony on the topic of Ameren Missouri's 2016-2018 Energy Efficiency Plan. On behalf of Sierra Club. March 20, 2015 and April 27, 2015.

Florida Public Service Commission (Dockets No. 130199-EI et al.): Direct testimony on the topic of setting goals for increasing the efficiency of energy consumption and increasing the development of demand-side renewable energy systems. On behalf of the Sierra Club. May 19, 2014.

Massachusetts Department of Public Utilities (Docket No. DPU 14-86): Direct and rebuttal Testimony regarding the cost of compliance with the Global Warming Solution Act. On behalf of the Massachusetts Department of Energy Resources and the Department of Environmental Protection. May 16, 2014.

Kentucky Public Service Commission (Case No. 2014-00003): Direct testimony regarding Louisville Gas and Electric Company and Kentucky Utilities Company's proposed 2015-2018 demand-side management and energy efficiency program plan. On behalf of Wallace McMullen and the Sierra Club. April 14, 2014.

Maine Public Utilities Commission (Docket No. 2013-168): Direct and surrebuttal testimony regarding policy issues raised by Central Maine Power's 2014 Alternative Rate Plan, including recovery of capital costs, a Revenue Index Mechanism proposal, and decoupling. On behalf of the Maine Public Advocate Office. December 12, 2013 and March 21, 2014.

Colorado Public Utilities Commission (Docket No. 13A-0686EG): Answer and surrebuttal testimony regarding Public Service Company of Colorado's proposed energy savings goals. On behalf of the Sierra Club. October 16, 2013 and January 21, 2014.

Kentucky Public Service Commission (Case No. 2012-00578): Direct testimony regarding Kentucky Power Company's economic analysis of the Mitchell Generating Station purchase. On behalf of the Sierra Club. April 1, 2013.

Nova Scotia Utility and Review Board (Matter No. M04819): Direct testimony regarding Efficiency Nova Scotia Corporation's Electricity Demand Side Management Plan for 2013 – 2015. On behalf of the Counsel to Nova Scotia Utility and Review Board. May 22, 2012.

Missouri Office of Public Counsel (Docket No. EO-2011-0271): Rebuttal testimony regarding IRP rule compliance. On behalf of the Missouri Office of the Public Counsel. October 28, 2011.

Nova Scotia Utility and Review Board (Matter No. M03669): Direct testimony regarding Efficiency Nova Scotia Corporation's Electricity Demand Side Management Plan for 2012. On behalf of the Counsel to Nova Scotia Utility and Review Board. April 8, 2011.

Rhode Island Public Utilities Commission (Docket No. 3790): Direct testimony regarding National Grid's Gas Energy Efficiency Programs. On behalf of the Division of Public Utilities and Carriers. April 2, 2007.

North Carolina Utilities Commission (Docket E-100, Sub 110): Filed comments with Anna Sommer regarding the Potential for Energy Efficiency Resources to Meet the Demand for Electricity in North Carolina. Synapse Energy Economics on behalf of the Southern Alliance for Clean Energy. February 2007.

Rhode Island Public Utilities Commission (Docket No. 3765): Direct and Surrebuttal testimony regarding National Grid's Renewable Energy Standard Procurement Plan. On behalf of the Division of Public Utilities and Carriers. January 17, 2007 and February 20, 2007.

Minnesota Public Utilities Commission (Docket Nos. CN-05-619 and TR-05-1275): Direct testimony regarding the potential for energy efficiency as an alternative to the proposed Big Stone II coal project. On behalf of the Minnesota Center for Environmental Advocacy, Fresh Energy, Izaak Walton League of America, Wind on the Wires and the Union of Concerned Scientists. November 29, 2006.

Rhode Island Public Utilities Commission (Docket No. 3779): Oral testimony regarding the settlement of Narragansett Electric Company's 2007 Demand-Side Management Programs. On behalf of the Division of Public Utilities and Carriers. November 24, 2006.

Nevada Public Utilities Commission (Docket Nos. 06-04002 & 06-04005): Direct testimony regarding Nevada Power Company's and Sierra Pacific Power Company's Renewable Portfolio Standard Annual Report. On behalf of the Nevada Bureau of Consumer Protection. October 26, 2006

Nevada Public Utilities Commission (Docket No. 06-06051): Direct testimony regarding Nevada Power Company's Demand-Side Management Plan in the 2006 Integrated Resource Plan. On behalf of the Nevada Bureau of Consumer Protection. September 13, 2006.

Nevada Public Utilities Commission (Docket Nos. 06-03038 & 06-04018): Direct testimony regarding the Nevada Power Company's and Sierra Pacific Power Company's Demand-Side Management Plans. On behalf of the Nevada Bureau of Consumer Protection. June 20, 2006.

Nevada Public Utilities Commission (Docket No. 05-10021): Direct testimony regarding the Sierra Pacific Power Company's Gas Demand-Side Management Plan. On behalf of the Nevada Bureau of Consumer Protection. February 22, 2006.

South Dakota Public Utilities Commission (Docket No. EL04-016): Direct testimony regarding the avoided costs of the Java Wind Project. On behalf of the South Dakota Public Utilities Commission Staff. February 18, 2005.

Rhode Island Public Utilities Commission (Docket No. 3635): Oral testimony regarding the settlement of Narragansett Electric Company's 2005 Demand-Side Management Programs. On behalf of the Division of Public Utilities and Carriers. November 29, 2004.

British Columbia Utilities Commission. Direct testimony regarding the Power Smart programs contained in BC Hydro's Revenue Requirement Application 2004/05 and 2005/06. On behalf of the Sierra Club of Canada, BC Chapter. April 20, 2004.

Maryland Public Utilities Commission (Case No. 8973): Oral testimony regarding proposals for the PJM Generation Attributes Tracking System. On behalf of the Maryland Office of People's Counsel. December 3, 2003.

Rhode Island Public Utilities Commission (Docket No. 3463): Oral testimony regarding the settlement of Narragansett Electric Company's 2004 Demand-Side Management Programs. On behalf of the Division of Public Utilities and Carriers. November 21, 2003.

California Public Utilities Commission (Rulemaking 01-10-024): Direct testimony regarding the market price benchmark for the California renewable portfolio standard. On behalf of the Union of Concerned Scientists. April 1, 2003.

Québec Régie de l'énergie (Docket R-3473-01): Direct testimony with Philp Raphals regarding Hydro-Québec's Energy Efficiency Plan: 2003-2006. On behalf of Regroupment national des Conseils régionaux de l'environnement du Québec. February 5, 2003.

Connecticut Department of Public Utility Control (Docket No. 01-10-10): Direct testimony regarding the United Illuminating Company's service quality performance standards in their performance-based ratemaking mechanism. On behalf of the Connecticut Office of Consumer Counsel. April 2, 2002.

Nevada Public Utilities Commission (Docket No. 01-7016): Direct testimony regarding the Nevada Power Company's Demand-Side Management Plan. On behalf of the Bureau of Consumer Protection, Office of the Attorney General. September 26, 2001.

United States Department of Energy (Docket Number-EE-RM-500): Comments with Bruce Biewald, Daniel Allen, David White, and Lucy Johnston of Synapse Energy Economics regarding the Department of Energy's proposed rules for efficiency standards for central air conditioners and heat pumps. On behalf of the Appliance Standards Awareness Project. December 2000.

US Department of Energy (Docket EE-RM-500): Oral testimony at a public hearing on marginal price assumptions for assessing new appliance efficiency standards. On behalf of the Appliance Standards Awareness Project. November 2000.

Connecticut Department of Public Utility Control (Docket No. 99-09-03 Phase II): Direct testimony regarding Connecticut Natural Gas Company's proposed performance-based ratemaking mechanism. On behalf of the Connecticut Office of Consumer Counsel. September 25, 2000.

Mississippi Public Service Commission (Docket No. 96-UA-389): Oral testimony regarding generation pricing and performance-based ratemaking. On behalf of the Mississippi Attorney General. February 16, 2000.

Delaware Public Service Commission (Docket No. 99-328): Direct testimony regarding maintaining electric system reliability. On behalf of Delaware Public Service Commission Staff. February 2, 2000.

Delaware Public Service Commission (Docket No. 99-328): Filed expert report ("Investigation into the July 1999 Outages and General Service Reliability of Delmarva Power & Light Company," jointly authored with J. Duncan Glover and Alexander Kusko). Synapse Energy Economics and Exponent Failure Analysis Associates on behalf the Delaware Public Service Commission Staff. February 1, 2000.

New Hampshire Public Service Commission (Docket No. 99-099 Phase II): Oral testimony regarding standard offer services. On behalf of the Campaign for Ratepayers Rights. January 14, 2000.

West Virginia Public Service Commission (Case No. 98-0452-E-GI): Rebuttal testimony regarding codes of conduct. On behalf of the West Virginia Consumer Advocate Division. July 15, 1999.

West Virginia Public Service Commission (Case No. 98-0452-E-GI): Direct testimony regarding codes of conduct and other measures to protect consumers in a restructured electricity industry. On behalf of the West Virginia Consumer Advocate Division. June 15, 1999.

Public Service Commission of West Virginia (Case No. 98-0452-E-GI): Filed expert report ("Measures to Ensure Fair Competition and Protect Consumers in a Restructured Electricity Industry in West Virginia," jointly authored with Jean Ann Ramey and Theo MacGregor) in the matter of the General Investigation to determine whether West Virginia should adopt a plan for open access to the electric power supply market and for the development of a deregulation plan. Synapse Energy Economics and MacGregor Energy Consultancy on behalf of the West Virginia Consumer Advocate Division. June 1999.

Massachusetts Department of Telecommunications and Energy (DPU/DTE 97-111): Direct testimony regarding Commonwealth Electric Company's energy efficiency plan, and the role of municipal aggregators in delivering demand-side management programs. On behalf of Cape and Islands Self-Reliance Corporation. January 1998.

Delaware Public Service Commission (DPSC 97-58): Direct testimony regarding Delmarva Power and Light's request to merge with Atlantic City Electric. On behalf of Delaware Public Service Commission Staff. May 1997.

Delaware Public Service Commission (DPSC 95-172): Oral testimony regarding Delmarva's integrated resource plan and DSM programs. On behalf of the Delaware Public Service Commission Staff. May 1996.

Colorado Public Utilities Commission (5A-531EG): Direct testimony regarding the impact of proposed merger on DSM, renewable resources and low-income DSM. On behalf of the Colorado Office of Energy Conservation. April 1996.

Colorado Public Utilities Commission (3I-199EG): Direct testimony regarding the impacts of increased competition on DSM, and recommendations for how to provide utilities with incentives to implement DSM. On behalf of the Colorado Office of Energy Conservation. June 1995.

Colorado Public Utilities Commission (5R-071E): Oral testimony on the Commission's integrated resource planning rules. On behalf of the Colorado Office of Energy Conservation. July 1995.

Colorado Public Utilities Commission (3I-098E): Direct testimony on the Public Service Company of Colorado's DSM programs and integrated resource plans. On behalf of the Colorado Office of Energy Conservation. April 1994.

Delaware Public Service Commission (Docket No. 96-83): Filed comments regarding the Investigation of Restructuring the Electricity Industry in Delaware (Tellus Institute Study No. 96-99). On behalf of the Staff of the Delaware Public Service Commission. November 1996.

Colorado Public Utilities Commission (Docket No. 96Q-313E): Filed comments in response to the Questionnaire on Electricity Industry Restructuring (Tellus Institute Study No. 96-130-A3). On behalf of the Colorado Governor's Office of Energy Conservation. October 1996.

State of Vermont Public Service Board (Docket No. 5854): Filed expert report (Tellus Institute Study No. 95-308) regarding the Investigation into the Restructuring of the Electric Utility Industry in Vermont. On behalf of the Vermont Department of Public Service. March 1996.

Pennsylvania Public Utility Commission (Docket No. I-00940032): Filed comments (Tellus Institute Study No. 95-260) regarding an Investigation into Electric Power Competition. On behalf of The Pennsylvania Office of Consumer Advocate. November 1995.

New Jersey Board of Public Utilities (Docket No. EX94120585Y): Initial and reply comments ("Achieving Efficiency and Equity in the Electricity Industry Through Unbundling and Customer Choice," Tellus Institute Study No. 95-029-A3) regarding an investigation into the future structure of the electric power industry. On behalf of the New Jersey Division of Ratepayer Advocate. September 1995.

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Woolf, T., A. Sommer, J. Nielson, D. Berry, R. Lehr. 2005. "Managing Electricity Industry Risk with Clean and Efficient Resources." *The Electricity Journal* 18 (2): 78–84.

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Resume dated March 2018

ATTACHMENT C

Before the
Rhode Island Public Utilities Commission

Proceeding on the Narragansett Electric	)	
Company d/b/a National Grid Proposed	)	Docket No. 4770
Tariff Changes	)	

Direct Testimony of
Tim Woolf and Melissa Whited

On Behalf of

The Division of Public Utilities and Carriers

April 6, 2018

Table of Contents

1. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name, title, and employer.

A. **Mr. Woolf:** My name is Tim Woolf. I am the Vice President at Synapse Energy Economics, located at 485 Massachusetts Avenue, Cambridge, MA 02139.

A. **Ms. Whited:** My name is Melissa Whited. I am a Principal Associate at Synapse Energy Economics, located at 485 Massachusetts Avenue, Cambridge, MA 02139.

Q. Please describe Synapse Energy Economics.

A. Synapse Energy Economics is a research and consulting firm specializing in electricity and gas industry regulation, planning, and analysis. Our work covers a range of issues, including economic and technical assessments of demand-side and supply-side energy resources; energy efficiency policies and programs; integrated resource planning; electricity market modeling and assessment; renewable resource technologies and policies; and climate change strategies. Synapse works for a wide range of clients, including state attorneys general, offices of consumer advocates, trade associations, public utility commissions, environmental advocates, the U.S. Environmental Protection Agency, U.S. Department of Energy, U.S. Department of Justice, the Federal Trade Commission, and the National Association of Regulatory Utility Commissioners. Synapse has over 25 professional staff with extensive experience in the electricity industry.

Q. Please summarize your professional and educational experience.

A. **Mr. Woolf:** Before joining Synapse Energy Economics, I was a commissioner at the Massachusetts Department of Public Utilities (DPU) from 2007 through 2011. In that capacity, I was responsible for overseeing a substantial expansion of clean energy policies, including significantly increased ratepayer-funded energy efficiency programs; an update of the DPU energy efficiency guidelines; the implementation of decoupled rates for electric and gas companies; the promulgation of net metering regulations; review and approval of smart grid pilot programs; and review and approval of long-term contracts for renewable power. I was also responsible for overseeing a variety of other dockets before the Commission, including several electric and gas utility rate cases.

Prior to being a commissioner at the Massachusetts DPU, I was employed as the Vice President at Synapse Energy Economics; a Manager at Tellus Institute; the Research Director at the Association for the Conservation of Energy; a Staff Economist at the Massachusetts Department of Public Utilities; and a Policy Analyst at the Massachusetts Executive Office of Energy Resources.

I hold a Masters in Business Administration from Boston University, a Diploma in Economics from the London School of Economics, a BS in Mechanical Engineering and a BA in English from Tufts University. My resume is attached as Exhibit TW/MW-1.

A. **Ms. Whited:** I have seven years of experience in economic research and consulting. At Synapse, I have worked extensively on issues related to utility regulatory models, rate design, policies to address distributed energy resources (DER), and market power. I have testified before the Massachusetts Department of Public Utilities, the Hawaii Public Utilities Commission, the Public Service Commission of Utah, the Public Utility Commission of Texas, the Virginia State Corporation Commission, and the Federal Energy Regulatory Commission.

I hold a Master of Arts in Agricultural and Applied Economics and a Master of Science in Environment and Resources, both from the University of Wisconsin-Madison. Prior to rejoining Synapse, I published an article in the Journal of Regional Analysis and Policy regarding the economic impacts of water transfers, analyzed state water efficiency policies while at the Wisconsin Public Service Commission, and conducted econometric analyses of energy efficiency cost-effectiveness. My resume is attached as Exhibit TW/MW-2.

Q. On whose behalf are you testifying in this case?

A. We are testifying on behalf of the Division of Public Utilities and Carriers (the Division).

Q. Have you previously testified before the Rhode Island Public Utilities Commission?

A. **Mr. Woolf:** Yes. I have testified before the Rhode Island Public Utilities Commission (the Commission) on behalf of the Division in National Grid’s (the Company’s) Energy Efficiency and System Reliability Plans. I was an active member of the Docket 4600 Working Group, and I assisted the Division with the Rhode Island Power Sector Transformation report recently submitted to Governor Raimondo. I also recently testified before the Commission on behalf of the Division in Docket 4783 on National Grid’s proposed advanced metering (AMF) pilot.

Ms. Whited: Yes. I recently testified before the Commission on behalf of the Division in Docket 4783 on National Grid’s proposed AMF pilot.

Q. What is the purpose of your testimony?

A. The purpose of our testimony is to review and comment on several topics that are directly related to rate case issues in this docket and are contained in the joint pre-filed direct testimony of National Grid's Power Sector Transformation (PST) Panel (the Panel). We address the Company's proposed performance incentive mechanisms (PIMs), because these are integrally related to the authorized ROE that will be set in this rate case. We address the Company's benefit-cost analyses (BCA), because these are used to determine the PIM incentives that will affect the authorized ROE. We also address the Company's request for recovery of costs for the AMF study and for the distributed energy resources (DER) enablement investments, because recovery of these costs will affect the revenue requirements that are approved in this rate case.

Q. Is the Division sponsoring other witnesses that address issues related to your testimony?

A. Yes. The following Division witnesses address issues that are related to our testimony:

- Tim Woolf provides an overview of the Division's case in this docket. It introduces all of the Division's witnesses, presents the Division's overarching vision for power sector transformation, and addresses the role of multi-year rate plans in achieving that vision.
- Matt Kahal addresses cost of capital and return on equity (ROE) issues.
- Greg Booth addresses several elements of National Grid's Power Sector Transformation Plan that relate to this rate case, including advanced metering functionality and the grid modernization elements.
- Roger Colton addresses low-income issues, including those related to the A60 low-income discount rate.

2. SUMMARY OF CONCLUSIONS AND RECOMMENDATIONS

Q. Please summarize your conclusions.

A. Our conclusions are summarized as follows:

- The amount of change and evolution in today's power sector requires a more integrated, long-term approach to utility planning and ratemaking, relative to historical practices. All National Grid's planning initiatives (energy efficiency, system reliability and procurement, conventional distribution projects, grid modernization, power sector transformation) should be planned for, reviewed by stakeholders, and treated by the Commission in a more holistic way.
- Performance incentive mechanisms should play an integral role in the overall ratemaking approach used to achieve power sector transformation goals. PIMs can align utility financial incentives with regulatory priorities and offset some of the existing incentives that emphasize capital investments and hinders utility investment in DERs.
- PIMs are directly related to a utility's authorized ROE, because they both provide shareholder revenues and incentivize utility management decisions. These two topics must be addressed by the Commission together in a rate case, to promote economic decision-making, achieve desired performance outcomes, and avoid over-recovery (or under-recovery) of revenues by the Company.
- The shareholder revenues provided by existing and proposed PIMs will be significant enough to warrant the Commission establishing National Grid's authorized ROE at the lower end of the reasonable cost of equity range. Such a shifting of revenue sources will mitigate the Company's incentive to increase rate base and focus management's attention on achieving power sector transformation goals.
- National Grid's proposed PIMs are a reasonable attempt to improve the Company's incentives, consistent with the PST Report. However, many of them suffer from some critical design flaws. In particular:
    - The baseline for the FCM and the Transmission PIMs are based on a historical year, which does not properly account for the natural variations in the relevant metric.

- The Company does not have a forecast for its transmission peaks, which makes it difficult to determine reasonable targets.
- Several of the Company's PIMs have metrics that are not directly related to the desired outcome or are not needed because they address activities that the Company should be doing anyway.

- The Company's "new grid modernization" (i.e.,"DER-enabling") investments should not be treated separately from conventional investments or PST-related investments, either in terms of planning, regulatory oversight, or cost recovery.
- AMF can play a critical, foundational role in transforming the RI power sector, and will be necessary to achieve the outcomes and goals articulated by the Docket 4600 Working Group and the Commission's Guidance Document, particularly the goal of implementing time-varying rates. National Grid's BCA indicates that AMF could be cost-effective under several likely scenarios.
- National Grid's proposal to study AMF is an important step toward implementing AMF and achieving power sector transformation goals. However, the Division concludes that this study should be done for less than the $2 million asked for by the Company and should include examination of shared communications and third-party ownership models.
- National Grid's BCAs have limited value for determining the magnitude of PIM incentives because they do not include some important benefits and they use outdated avoided costs.

Q. Please summarize your recommendations.

A. Our recommendations are summarized as follows:

- The Commission should address National Grid's proposed PIMs in this rate case docket, to ensure that decisions regarding the Company's authorized ROE fully account for the shareholder revenues and the financial incentive implications of the PIMs.

- The Commission should adopt the set of PIMs proposed by the Division, as described in detail in our testimony below. Table 1 provides a summary of the Division’s proposed PIMs.

Table 1. Summary of the Division’s Proposed PIMs

Type	PIM	Description
System Efficiency	Transmission Peak	Reduce transmission peaks relative to forecast
	FCM Peak	Reduce annual FCM peak relative to forecast
Distributed Energy Resources	Demand Response – Res.	Increase MW enrollment in cost-effective DR
	Demand Response - C&I	Increase MW enrollment in cost-effective DR
	Electric Heat Initiative	Increase MW of cost-effective electric heat
	Electric Vehicle Initiative	Reduce GHG emissions relative to baseline
	Behind-the-Meter Storage	Install MW of cost-effective storage
	Utility-Scale Storage	Install MW of cost-effective storage
	Non-Wires Alternatives	Procure cost-effective NWA from third-parties
PST Support	Low Income: Participation	Increase LI participation in DER initiatives
	Low Income: Enrollment	Increase customer enrollment in LI rate A60
	Customer Information	Provide key data to customers and third-parties
	Peak Demand Forecasting	Improve and expand current forecasting practices

- The Commission should establish National Grid’s authorized ROE at the lower end of the cost of equity range to (a) account for the additional shareholder revenues from our proposed PIMs, and (b) mitigate the existing financial incentive to increase capital investments.
- The Commission should establish the regulatory procedures to be used to implement PIMs and allow the Company to recover the PIM incentives. This should include:
    - An annual Performance Incentive Mechanism Plan that presents all of the relevant metrics, targets, baselines, and incentives for the PIMs to be applied in the following calendar year.
    - An annual Performance Report that presents all of the historical data on the relevant metrics, targets, baselines, and incentives for the PIMs that were in place in the previous calendar year.

- An incentive recovery process that adjusts rates once per year to reflect the PIM incentives earned by the Company in the previous calendar year.

- The Commission should require the Company to file the first (i.e., 2019) PIM Plan by November 31, 2018. This plan should update all elements of the Company's PIMs based on the Commission findings and directives in this docket.
- The Commission should approve National Grid's request for funding of the AMF Study. However, the Commission should approve only $1 million of the requested funds.
- The Commission should require the Company to file grid modernization plans that comprehensively and consistently evaluate all distribution system opportunities over the long-term.
- The Commission should require the Company to treat "new grid modernization" investments comparably with its conventional distribution system investments.

3. THE ROLE OF PERFORMANCE INCENTIVE MECHANISMS

Q. The Commission has bifurcated the rate case docket (Docket 4770) from the power sector transformation docket (Docket 4780). Why is the Division sponsoring a witness to address performance incentive mechanisms in this rate case docket?

A. As described in the direct testimony of Mr. Woolf, PIMs should play an integral role in the overall ratemaking approach used to achieve power sector transformation goals. In conjunction with multi-year rate plans, PIMs can help align a utility's financial incentives with regulatory policy goals.

Performance incentive mechanisms and the authorized ROE serve similar and inter-related functions. They both provide revenues for the Company's shareholders, for the rate year and all the years until the next rate case. They also both provide utility management with financial incentives that can have a large impact on utility performance, utility rates, and services to customers. Because of this inter-relationship, it is critical for the Commission to consider the authorized ROE and the PIMs together. Otherwise, the ultimate impacts of these two mechanisms treated separately could lead to unintended consequences, uneconomic decision-making, undesirable performance outcomes, and over-recovery (or under-recovery) of revenues by the Company. These points are described in Section 4.2

For this reason, it is essential that the Commission consider PIMs in the context of Docket 4770. When determining the authorized ROE in Docket 4770, the Commission should recognize the significant amount of shareholder revenues that the Company could earn from PIM incentives. As we demonstrate in Section 4.2, potential shareholders revenues from existing and proposed PIMs could be 200 basis points or higher. This amount of shareholder revenues is too large to be ignored by the Commission as it makes important decisions regarding the Company's authorized ROE.

Q. What benefits do PIMs offer over traditional ratemaking practices?

A. PIMs offer many advantages relative to traditional cost-of-service ratemaking, including:[1]

- They help to make regulatory goals and incentives explicit.
- They allow regulators to offset or mitigate those current financial incentives that are not well aligned with the public interest.
- They allow regulators to improve utility performance in specific areas where historical performance has been unsatisfactory.

[1] These are taken from Synapse Energy Economics, *Utility Performance Incentive Mechanisms: A Handbook for Regulators*, Prepared for the Western Interstate Energy Board, March 2015, page 1.

- Where utilities are subject to economic and regulatory cost-cutting pressures, they can encourage utilities to maintain, or even improve, customer service, customer satisfaction, and other relevant performance areas.
- They allow regulators to provide specific guidance on important state and regulatory policy goals.
- They allow regulators to give more attention to whether the desired outcomes are achieved, and spend less time evaluating the specific costs and means to obtain those outcomes.
- They can help provide greater regulatory guidance to address new and emerging issues, such as grid modernization, or to attain specific policy goals, such as promoting clean energy resources.
- They can help support new regulatory models that provide utilities with greater incentives to achieve desired outcomes and that tie utilities' profits more to performance than to capital investments.
- They can be applied incrementally, providing a flexible, relatively low-risk regulatory option.

Q. Please provide brief definitions of the terms that are used in reference to PIMs.

A. It is important to distinguish between several different components of performance incentive mechanisms. In this testimony we will use the following terms:

- Performance area; refers to the type of performance or desired outcome that the PIM is trying to influence (e.g., FCM peak demand).
- Metric; refers to the type of data that is used to track and monitor the performance or desired outcome (e.g., actual FCM peak demand, relative to a baseline).
- Baseline; refers to the counterfactual case of what would have occurred in the absence of the PIM. (e.g., the forecasted 2019 FCM peak demand.)
- Target; refers to a specific goal that the utility is directed to achieve (e.g., 29 MW reduction in the FCM peak demand in 2019).

- Deadband; a deadband is a region around the target within which the Company would not earn a reward (e.g., 14.5 MW below the forecasted 2019 FCM peak demand). The concept of a deadband is often used to account for uncertainty regarding the target or to allow for some deviation from the target due to factors outside of utility control.
- Incentive; refers to the amount of money that the utility can be rewarded for performance relative to the target (e.g., five basis points for achieving the 2019 FCM peak demand reduction target). The financial incentive can be expressed in terms of basis points on the utility's return on equity, as we do in this testimony.[2]

Q. Why are PIMs appropriate for National Grid, given that the Company has multiple statutory and regulatory obligations to provide service to customers and maintain the distribution grid; including the overall obligation to provide safe, reliable, clean, and affordable electricity services?

A. First, PIMs encourage utilities to focus on specific outcomes or goals that warrant additional attention from a policy perspective, even if those outcomes or goals are consistent with historical core performance areas. Utility management must balance multiple objectives, and may need regulatory guidance and incentives to help prioritize outcomes or goals that are important to the Commission.

Second, utilities currently have a financial incentive to maximize profits by expanding capital investments and increasing rate base.[3] This can lead to lead to undue emphasis on capital investments, resulting in projects that are not least-cost for customers. PIMs can be used to offset these financial incentives, and are thus a critical

[2] Although the incentive may be expressed in terms of basis points, achievement of the incentive would be implemented through the utility collecting the dollar equivalent, rather than by actually increasing the utility's allowed ROE.

[3] This incentive exists where the utility's authorized ROE exceeds the cost of capital, as is often the case.

step toward establishing a new utility business model more aligned with power sector transformation.

Third, PIMs can be used to encourage a utility to undertake a particular project (such as a PST initiative) in a way that is most efficient, with reduced costs or increased benefits or both, relative to what would occur in the absence of a PIM.

Q. The Division addressed PIMs in the Power Sector Transformation Phase I Report. Does the current proposal differ from that described in the PST Report?

A. Yes. Although the overall approach to PIMs remains consistent, the proposal has naturally evolved since November 2017 based on information gained from the Company through the discovery process and from the analysis described in this testimony and manifest in Exhibit 4.

4. THE DIVISION'S PERFORMANCE INCENTIVE MECHANISM PROPOSAL

4.1. Summary of the Division PIM Proposal

Q. Please provide a brief summary of the Division's PIM proposal.

A. The Division's proposal is summarized in Table 2, Table 3, Table 4, and Figure 1. Our proposal builds off National Grid's PIM proposal in many ways. The primary areas where we deviate from the Company are in some of the baselines, some of the metrics, some of the targets, and in the BCA used to determine PIM incentives. Additional details for the Division's proposal are provided in Sections 4.4, 4.5, and 4.6 below.

Table 2. The Division's Proposed PIMs

Type	PIM	Description
System Efficiency	Transmission Peak	Reduce monthly transmission peaks relative to forecast
	FCM Peak	Reduce annual FCM peak relative to forecast
Distributed Energy Resources	Demand Response – Res.	Increase MW enrollment in cost-effective DR
	Demand Response - C&I	Increase MW enrollment in cost-effective DR
	Electric Heat Initiative	Reduce GHG emissions relative to baseline
	Electric Vehicle Initiative	Reduce GHG emissions relative to baseline
	Behind-the-Meter Storage	Install MW of cost-effective storage
	Utility-Scale Storage	Install MW of cost-effective storage
	Non-Wires Alternatives	Procure cost-effective NWA from third-parties
PST Support	Low Income: Participation	Increase LI participation in DER initiatives
	Low Income: Enrollment	Increase customer enrollment in LI rate A60
	Customer Information	Provide key data to customers and third-parties
	Peak Demand Forecasting	Improve and expand current forecasting practices

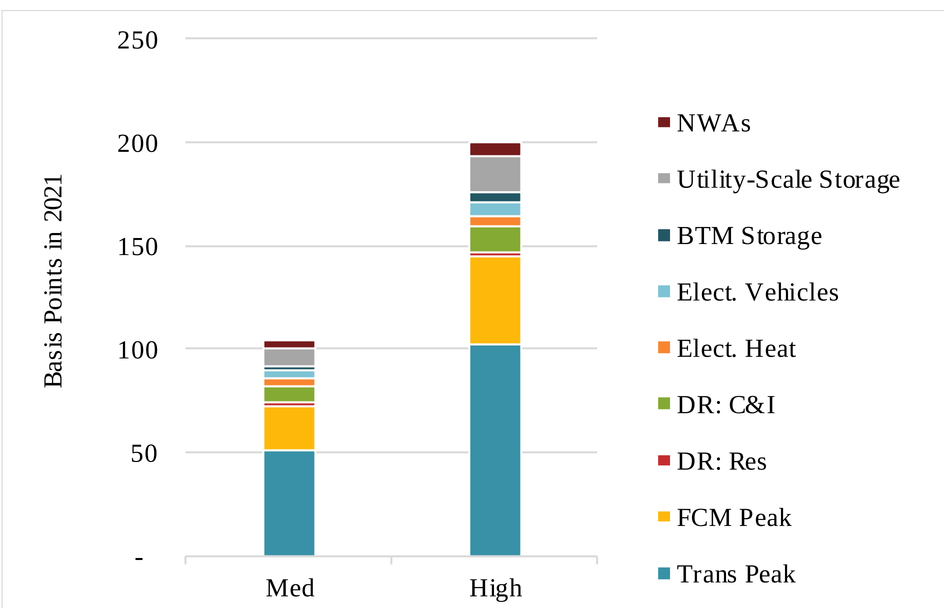
Table 3. Division's Proposed PIM Targets

Type	PIM	2019 (med)	2019 (high)	2020 (med)	2020 (high)	2021 (med)	2021 (high)
System Efficiency	Transmission Peak (Avg MW/mo)	21	31	23	35	26	39
	FCM Peak	29	44	31	46	32	48
	Subtotal						
Distributed Energy Resources	DR: Residential (MW)	1	2	2	3	3	4
	DR: C&I (MW)	8	14	10	16	12	18
	Electric Heat Initiative (GHG)	464	556	580	696	595	714
	Electric Vehicles (GHG)	557	1,114	757	1,511	1,026	2,051
	BTM Storage (MW)	1	2	1	2	1	2
	Utility-Scale Storage (MW)	3	6	3	6	3	6
	Non-Wires Alternatives (MW)	3	6	3	6	3	6
	Subtotal						
PST Support	LI: PST Participation						
	LI: Enrollment						
	Customer Information						
	Peak Forecasting						
	Subtotal PST Support						
Total							

Table 4. Division's Proposed PIM Incentives (bps)

Type	PIM	2019 (med)	2019 (high)	2020 (med)	2020 (high)	2021 (med)	2021 (high)
System Efficiency	Transmission Peak	40	80	46	93	51	103
	FCM Peak	9	18	15	30	21	42
	Subtotal	49	98	61	122	73	145
Distributed Energy Resources	DR: Residential	1	1	1	1	1	2
	DR: C&I	3	4	5	8	8	12
	Electric Heat Initiative	3	5	4	5	4	5
	Electric Vehicles	3	4	3	6	4	7
	BTM Storage	1	3	2	3	2	4
	Utility-Scale Storage	3	7	6	12	9	17
	Non-Wires Alternatives	2	4	3	6	4	8
	Subtotal	16	27	24	41	32	55
PST Support	LI: PST Participation	2	3	2	3	2	3
	LI: Enrollment	2	3	2	3	2	3
	Customer Information	1	2	0	0	0	0
	Peak Forecasting	1	2	0	0	0	0
	Subtotal PST Support	6	10	4	6	4	6
Total		71	135	89	169	108	206

Figure 1. Division's Proposed PIM Incentives in 2021 (bps)



4.2. Implications for the Authorized Return on Equity

Q. Why is it important to consider the Company's authorized ROE in conjunction with performance incentive mechanisms?

A. As described above, the Company's authorized ROE and PIMs serve similar and inter-related functions. They both provide revenues for the Company's shareholders, for the rate year and all the years until the next rate case. They also both provide utility management with financial incentives that can have a large impact on utility performance, utility rates, and services to customers. Because of this inter-relationship, it is critical for the Commission to consider the authorized ROE and the PIMs together; otherwise the ultimate impacts of these two mechanisms treated separately could lead to unintended consequences, uneconomic decision-making; undesirable performance outcomes, and over-recovery (or under-recovery) of revenues by the Company.

Q. Please expand upon the implications of the financial incentive provided by the authorized ROE and the PIMs.

A. As discussed the direct testimony of Mr. Woolf, utilities subject to traditional rate of return regulation have a financial incentive to increase profits by increasing capital expenditures and increasing their rate base. This incentive can lead to uneconomic decision-making as a result of an overstated incentive to increase rate base, as well as too much emphasis on capital costs at the expense of operations and maintenance impacts. This preference to increase rate base can significantly dampen a utility's incentive to invest in DERs and other PST initiatives that can reduce capital costs. In order to fully achieve the goals of power sector transformation, it will be necessary to mitigate this undue preference for increased capital costs. PIMs offer a logical mechanism for doing so.

Q. Please describe how PIMs can mitigate a utility's preference for capital costs.

A. PIMs provide a utility with an alternative source of shareholders revenues. This can dampen a utility's emphasis on capital costs by providing another way to increase profits; ideally in a way that is more consistent with regulatory goals.

In addition, since PIMs provide an alternative source of shareholder revenues, regulators can establish the authorized ROE at the lower end of the cost of equity range to reflect those additional revenues that will increase profits. In our view, this is one of the most effective ways to modify the regulatory model to provide a utility the incentives it needs to achieve power sector transformation objectives.

Q. Please elaborate on what you mean by establishing the authorized ROE at the lower end of the range to reflect PIM revenues.

A. Mr. Kahal, addresses the appropriate way to determine an authorized ROE for National Grid in this rate case. Here, we will touch upon some of the key issues that pertain to the PIM revenues.

Setting the authorized ROE is not an exact science, and there are many techniques that can be used to identify the best value. Each of these techniques has strengths and limitations, and commissions are frequently presented with a range of reasonable recommendations for the authorized ROE. Commissions will typically select a number within this range, with the goal of balancing customer and shareholder interests.

In this context, the Commission could select an authorized ROE that is at the lower end of a reasonable range, in order to reflect the revenues that a utility is expected to recover through its PIMs. This lower authorized ROE could also be justified because the PIMs reduce the utility's risk by providing regulatory guidance and some assurance that the costs associated with PIM initiatives will be allowed into rates.

Q. Are you recommending that the authorized ROE be lowered by the same number of basis points that the Company is allowed to earn from the PIMs?

A. No. We are not necessarily recommending a one-for-one transfer of basis points from the authorized ROE to the PIMs. As described above, there are some significant uncertainties in the magnitudes of the PIM incentives proposed by the Company and by us. Further, some of the PIMs incentives are for innovative initiatives that might not provide net benefits to customers or utility incentives in the early years. We recommend that the authorized ROE be set a level sufficiently below the expected PIM incentives, to ensure that shareholders are not exposed to the risk of not recovering enough revenues.

Q. Is there evidence from existing PIMs that suggests that reducing the Company's authorized ROE is warranted?

A. Yes. The Company has been subject to an energy efficiency PIM since 1990. In our view, the energy efficiency PIM is very robust in terms of the estimates of the costs, benefits, net benefits, and targets, all of which are vetted by stakeholders in multiple forums and are documented with independent evaluation, measurement, and verification studies. The energy efficiency programs and PIM have clearly resulted in significant net benefits to customers over many years.

The energy efficiency PIM has also increased the Company's earned ROE. Table 5 presents the Company's earned ROE for recent years for which data is available, and breaks out the impact that the EE incentive has on earned ROE. As indicated, in the past three years the EE incentive helped increase the Company's earned ROE by 95 to 98 basis points. This is a significant impact on earned ROE, which demonstrates that the revenue from PIM incentives can create room for the Commission to establish a lower authorized ROE without harming utility shareholders. It also demonstrates the importance of considering PIM incentives and authorized ROE together.

Table 5. National Grid Earned ROEs: Including and Excluding the EE Incentive

Year	Earned ROE Excluding EE Incentive	Earned ROE Including EE Incentive	Basis Point Value of Earned EE Incentive
2013	6.98%	7.57%	59
2014	7.52%	8.50%	98
2015	8.28%	9.24%	96
2016	5.84%	6.79%	95

Q. What is the potential amount of basis points that the Company might earn from all the PIMs proposed by the Division?

A. Table 6 provides a summary of the amount of basis points that the Company could earn under the Division's proposed PIMs. It also includes the basis points that the Company could earn from the existing EE PIM, and all the PIMs combined.

Table 6. Potential Incentive Earnings from PIMs (basis points)

Performance Incentive Mechanism	2019 (med)	2019 (high)	2020 (med)	2020 (high)	2021 (med)	2021 (high)
Division's Proposed PIMs	71	135	89	169	108	206
Existing Energy Efficiency PIM	105	105	90	90	86	86
Total PIMs	176	240	179	259	194	292

As indicated, the Company will have the opportunity to earn 176 to 194 basis from the existing and proposed PIMs for achieving the medium targets. The incentives could be considerably higher for achieving the high targets.

4.3. Principles and Methodology for Developing the Division's Proposal

Q. In general, what principles should be used when designing PIMs?

A. Table 7 below presents a summary of the key principles that should be applied when designing PIMs, including principles related to (a) identifying policy goals; (b) establishing metrics; (c) establishing performance targets; and (d) establishing rewards and penalties.[4]

[4] These are taken from Synapse Energy Economics, *Utility Performance Incentive Mechanisms: A Handbook for Regulators*, Prepared for the Western Interstate Energy Board, March 2015, page 4.

Table 7. Key Principles for Developing Performance Incentive Mechanisms

Policy Goals	• Articulate policy goals • Recognize financial incentives in the existing regulatory system • Design incentives to modify, supplement or balance existing incentives • Address areas of utility performance that have not been satisfactory or are not adequately addressed by other incentives
Performance Metrics	• Tie metrics to policy goals • Clearly define metrics • Ensure metrics can be readily quantified using reasonably available data • Adopt metrics that are reasonably objective and largely independent of factors beyond utility control • Ensure metrics can be easily interpreted and independently verified
Performance Targets	• Tie targets to regulatory policy goals • Balance costs and benefits • Set realistic targets • Incorporate stakeholder input • Use deadbands to mitigate uncertainty and variability • Use time intervals that allow for long-term, sustainable solutions • Allow targets to evolve
Rewards and Penalties	• Consider the value of symmetrical versus asymmetrical incentives • Ensure that any incentive formula is consistent with desired outcomes • Ensure a reasonable magnitude for incentives • Tie incentive formula to actions within the control of utilities • Allow incentives to evolve

Q. Please describe the specific principles that you used in developing the PIMs for National Grid.

A. We generally agree with the principles that the Company used in designing its PIMs:[5]

- Establish incentives that will appropriately reward the Company for successful delivery of activities, programs, investments, and outcomes that are foundational to power sector transformation;
- Align, to the extent possible, with the proposed performance incentive mechanisms in the Power Sector Transformation Phase One Report; and

[5] PST Panel Direct Testimony, January 12, 2018, page 88.

- Assign values to individual performance incentive mechanisms based on a combination of (1) relevance to developing a foundation for transforming the power sector in the near term, and (2) the associated benefits or savings to customers due to the activity encouraged by the incentive.[6]

We also applied several additional, more specific principles in designing the Division's PIMs:

- Establish a portfolio of PIMs that is as simple and transparent as possible. This is particularly important because some of the Company's PIM proposals are complex and opaque.
- Establish a portfolio of PIMs that has an appropriate balance between outcome-based (e.g., system efficiency), program-based (e.g., distributed energy resources), and action-based (e.g., data access). Each of these types of PIMs has different strengths and challenges, so it is best to use a balanced mix of them.
- Establish at least one PIM for each of the DERs that are expected to play a foundational role in power sector transformation over the long-term. This is necessary to send a signal to the Company of the importance of each type of DER.
- Establish metrics and targets that are as concrete and as directly related to the desired outcomes as possible. This is particularly important here because some of the Company's proposed PIM targets are not directly related to the desired outcomes.

Q. Please describe how you determined the magnitude of the incentives for each of the PIMs you propose.

A. Determining the magnitude of incentives is one of the more challenging aspects of designing PIMs. Ideally, a PIM incentive should be designed to ensure that it will result in net benefits to customers. This requires first estimating the benefits and the costs of the

[6] PST Panel Direct Testimony, p. 88, lines 12-20.

initiative or action that the PIM applies to, and then deciding upon the appropriate portion of the net benefits to provide to the utility relative to the customers. This was essentially the approach that National Grid used in designing its proposed incentives.

We used the same approach in designing our incentives. However, given that our PIMs are structured somewhat differently from the Company's, and given that we have some concerns about National Grid's BCA assumptions, we developed PIM incentives independently from the Company's. We took the following steps:

- Update or otherwise modify the avoided costs that National Grid used in its BCAs. This includes using more recent information on forecast FCM prices, energy prices, and transmission costs. It also includes adding in our own assumption for avoided distribution capacity costs.
- Apply those new avoided costs to the PIM targets to estimate the quantitative benefits expected from achieving each of the PIMs in terms of peak demand reductions, peak energy savings, and greenhouse gas emissions. For each PIM, we made assumptions regarding the extent to which the utility's actions would reduce FCM, transmission, and distribution system peaks (using assumed coincidence factors).
- Estimate the likely costs of each of the PIM initiatives, to estimate the PIM's quantitative net benefits.
- Assume a percentage of net benefits to be shared between the Company and its customers, to estimate a dollar value for the PIM incentive.
- Convert this dollar value of the PIM incentive into basis points for the Company. For this purpose we used the Company's information for the value of a basis point.
- Identify additional unquantified benefits associated with each of the PIMs. These were assumed to be in the form of (a) improved reliability or resilience; (b) other

fuel benefits; (c) market innovation or transformation benefits; or (d) low-income benefits.

- Assign basis points for these unquantified benefits. The number of basis points for each PIM was chosen based upon the type and number of unquantified benefits, and the importance of each unquantified benefit in light of Docket 4600 goals and state energy policies.
- Add the basis point incentives for the quantified benefits to those for the unquantified benefits, to determine the total basis point incentive.

Additional details and assumptions underlying these steps are provided in Exhibit TW/MW-3.

Q. How did you incorporate the objective of ensuring consistent compensation for benefits across various performance incentive mechanisms?

A. We achieved a significant degree of consistency. The methodology to determine the magnitude of PIM incentives includes as a common input the benefits related to FCM capacity, distribution, greenhouse gas emission reductions, transmission, and energy. Those benefits populate our workbook consistently across individual performance incentive mechanisms.

Q. The methodology you describe for determining the magnitude of the PIM incentives includes multiple assumptions and estimates. Please comment.

A. Given that the magnitude of the PIM incentives should be based as much as possible on the net benefits, and given that the initiatives that the PIMs are applied to can be new or innovative, there is naturally a need to make some assumptions and estimates to determine those net benefits.

Q. Please describe those assumptions and estimates that are mostly likely to affect the results of your analyses.

A. The assumptions and estimates that are mostly likely to affect the results of our analyses include the following:

- Avoided FCM, energy, and transmission costs. These will have a large impact on the benefits of the PIM initiative. We have used recent values from an analysis provided at our request by Daymark Energy Advisors which we reviewed and believe is very reasonable. We are confident that these assumptions are robust for our purposes.
- Avoided distribution costs. The Company chose to not include these benefits, because of the challenges of estimating a value. We are concerned that this decision ignores a potentially significant benefit from DERs. Therefore, we have assumed the same avoided transmission costs that are used for evaluating energy efficiency cost-effectiveness in Rhode Island. We recognize that this number is a rough approximation, and that the value is likely higher for some distribution circuits and lower for others.
- Cost of the PIM initiative. The cost of an initiative or technology will clearly have a large impact on its net benefits. For the FCM Peak and Transmission Peak PIMs we assumed that there will be no additional cost to the customers, because the Company has not requested recovery of any such costs in this rate case. For some of the PIM initiatives (e.g., residential demand response, behind-the-meter storage), the costs are not known at this time. Our cost estimates are based on our understanding of the general cost-effectiveness of the relevant technology or initiative.
- PIM initiative or technology measure life. This assumption can have a very large impact on the estimated benefits of a PIM initiative. Some of the actions taken in the PIM initiatives might have measure lives of only one year (e.g., a demand response program), while others could have measure lives of ten or twenty years

(e.g., electric vehicles or electric heating). Our measure life assumptions are based on our understanding of the technologies and practices that are likely to be used in each PIM initiative.

- Coincidence of a PIM initiative or technology with the FCM, transmission, or distribution system peak. These coincidence factors are likely to vary across initiatives and technologies, and can have a very large impact on the estimated benefits of a PIM initiative. Our coincidence estimates are based on our understanding of the likely operating parameters of the relevant technology.

Q. Given all these assumptions and estimates that can significantly affect the outcome of your analysis, are you confident that your analysis can be used at this time to determine the magnitude of PIMs for National Grid?

A. Yes. There is no question that additional time and analyses will result in more robust assumptions than those that we have used here. Nonetheless, our assumptions and estimates are reasonable for our purpose here, for two reasons. First, in designing our PIMs we have used a shared savings approach as much as possible to determine the magnitude of the PIM incentives. A shared savings approach will provide the Company with a certain portion of the net benefits of achieving a PIM target. The net benefits will be determined after the year in which the target was achieved, at which time the actual costs of the actions taken by the Company will be known. This approach means that, for PIMs with a shared savings approach, the Company will only be awarded PIM incentives if there are actual net benefits to customers. It also means that the magnitude of the PIM incentive will depend upon the magnitude of the net benefits.

Second, as discussed in Section 4.7, the PIMs that we are proposing here would not take effect until January 2019, and would be preceded by a filing from the Company that provides up-to-date information, assumptions, and estimates on all aspects of the

PIMs, including the estimates of net benefits. The analyses that are presented in our testimony are illustrative but are not the final analyses that should be used to set the PIM incentives. Consequently, they are sufficiently robust for the Commission to take the next step on the proposed PIMs and direct the Company to file more detailed PIM proposals at a later date.

Q. Do you propose to include any penalties in your PIMs?

A. No. There are several reasons why we prefer to not apply penalties for the PIMs we propose here, primarily based on our findings from energy efficiency PIMs applied in other states. First, the initiatives that we are asking the Company to undertake are somewhat new. This means that there is some uncertainty about the costs, the benefits, and the outcomes of the initiatives. In this context, assigning penalties to the PIMs will be more likely to discourage the Company from pursuing an initiative than encourage it.

Second, if the Company is likely to be subjected to penalties for not achieving a specific PIM target, then it will be less likely to propose aggressive, or even reasonable, targets.

Third, applying penalties can be much more contentious than applying rewards. Having to return revenues that the Company was otherwise planning to retain can be a very undesirable outcome for utility management, and they might be more inclined to challenge any such penalty.

Q. Do you offer any other modifications to the Company's proposal?

A. Yes, a minor but important modification. The Company proposes PIM targets for minimum, target, and maximum levels. For any PIM in which there are shared savings, there is no need to cap targets (and associated incentives) at a maximum level. If the Company can increase net benefits associated with a PIM initiative by exceeding the maximum target, then it should be encouraged to do so. For this reason, we refer to the highest target level as the "high" target, instead of the "maximum" target. We also refer to the middle target as the "medium" target, instead of the "target."

4.4. Division's Proposed System Efficiency PIMs

Q. Please summarize your rationale for the system efficiency PIMs.

A. System efficiency PIMs can play an important role in the total portfolio of utility PIMs. The system efficiency PIMs proposed here can be described as "outcome-based," because they focus on the desired outcome, rather than on the means to achieve that outcome. This approach is fundamentally different than "program-based" PIMs, such as the DER PIMs described below, which are implemented through specific initiatives or programs.

Outcome-based programs require relatively little regulatory oversight as they allow the utility to determine the best way to achieve the desired outcome. The advantage of this is that the utility has a lot of flexibility to be creative and innovative in achieving the desired outcome. The disadvantage of this approach is that regulators have much less opportunity to identify, monitor, and evaluate the actions taken by the utility to achieve the outcome.

Program-based PIMs, on the other hand, require relatively more regulatory oversight in order to ensure that the programs are cost-effective, properly funded, and executed efficiently.[7] The advantage of this approach is that regulators can have more involvement, certainty, and confidence in the program and the related PIM. The disadvantage of this approach is that it might constrain the utility's creativity, and the regulatory oversight might be overly cumbersome.

Because of these different strengths and limitations of the two types of PIMs, we recommend a balanced approach that includes them both. This should offer the right amount of regulatory oversight and guidance, while enabling the utility to be creative and innovative.

Q. Please describe the Division's proposal for an FCM Peak Demand Reduction PIM.

A. Company activities to reduce FCM peak demand could significantly reduce generation capacity costs and play a foundational role in achieving power sector transformation objectives. Under current ratemaking practice, National Grid has little financial incentive to reduce FCM peak demand, because FCM costs are entirely passed on to customers. An FCM PIM can help create such an incentive while also creating net benefits to customers.

We propose that the metric for the FCM PIM be the reduction in demand (in MW) for the single peak FCM hour for each year. The demand reduction would be calculated as the difference between a forecasted baseline FCM peak and the actual FCM peak for that year, rather than year-over-year reductions relative to 2018 peak, as proposed by the Company. Both the baseline and the actual peaks would be calculated in weather-normalized terms. The baseline should also include the impacts of DERs that

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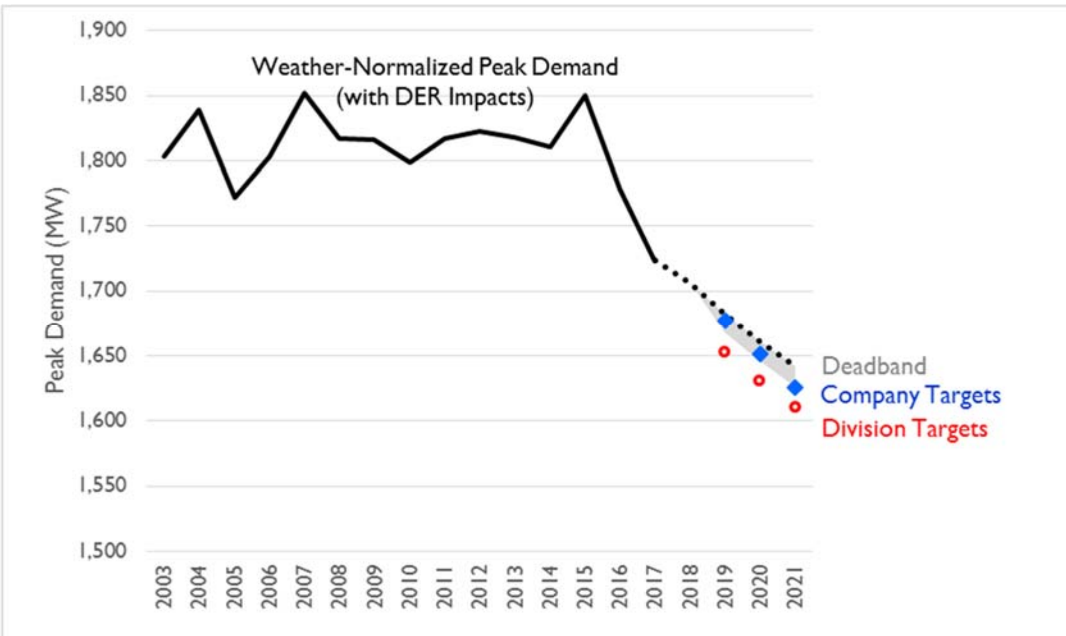
[7] Consider, for example, the regulatory oversight of the energy efficiency programs in Rhode Island.

the Company would be expected to earn an incentive for, so that there is no double-counting of savings.

For the weather-normalized baseline, we have used the Company's forecast of FCM peak demand for 2019, 2020, and 2021, including expected impacts from energy efficiency, solar PV, storage, VVO, and electric vehicles.[8] The peak demand forecast, along with our proposed deadband and PIM targets are presented in Figure 2.

Figure 2. FCM Peak Demand: Historical, Forecast, Deadband, and Targets



To account for uncertainty in the forecast and to ensure that the target is not something that could be met too easily by the utility, we propose a deadband equal to 0.5 standard errors of the forecast for each year.[9] We propose that the medium targets for the

[8] The Company provided these values in response to DIV 8-5. To illustrate, the Company's reconstituted forecast included load growth from 2018 to 2019 of 22.7 MW. However, the Company expects there will be 46.3 MW of load reductions through energy efficiency (35 MW), solar PV (7 MW), VVO (3 MW), and storage (1 MW). Because the Company proposes to earn incentives for these activities through other PIMs, we reduced the baseline by 46.3 MW, for a net reduction of 23.6 MW (22.7 – 46.3= -23.6).

[9] The standard error is a measure of the accuracy of the model, based on the difference between the model's estimated values and the actual values. For example, assuming a normal distribution with 10 degrees of freedom, 1.0 standard error is associated with an 83 percent level of confidence. This means that there is an 83 percent chance that a deviation from the

FCM PIM be set at 1.0 standard error below the forecast. This value of the standard error suggests that there is an 83 percent chance that the Company was responsible for the outcome. We also propose that the high target be set to 1.5 standard errors, which suggests that there is a 92 percent chance that the Company was responsible for the outcome. These targets are presented in Table 8. Note that these targets are relative to the baseline, including impacts from energy efficiency, solar PV, and other utility programs for which the Company proposes to earn an incentive. This means that, for example, in year 2019 the Company will need to reduce peak demand by 29 MW beyond the deadband. In that year the deadband amount is approximately 14.5 MW, which means that the Company will need to reduce FCM peak demand by 43.5 MW in order to reach this target.

We propose that the incentives for the FCM PIM be equal to 50 percent of the quantified net benefits of the FCM reductions achieved. We do not propose any additional basis points for unquantified benefits associated with FCM peak reductions, because we are not aware that there are any. These FCM incentives are presented in Table 8.

forecast is likely to be due to *something other than* the explanatory variables in the model, such as weather or the economy. In the context of defining PIM targets, a 1.0 standard error means that there is an 83 percent chance that the utility was responsible for the outcome.

Table 8. FCM Peak Demand Reduction PIM – Targets and Incentives

FCM Peak Demand Reduction	2019 (med)	2019 (high)	2020 (med)	2020 (high)	2021 (med)	2021 (high)
Targets (annual peak FCM MW savings)	29	44	31	46	32	48
Incentive for Quantified Benefits (bps)	9	18	15	30	21	42
Incentive for Unquantified Benefits (bps)	-	-	-	-	-	-
Total Incentive (bps)	9	18	15	30	21	42

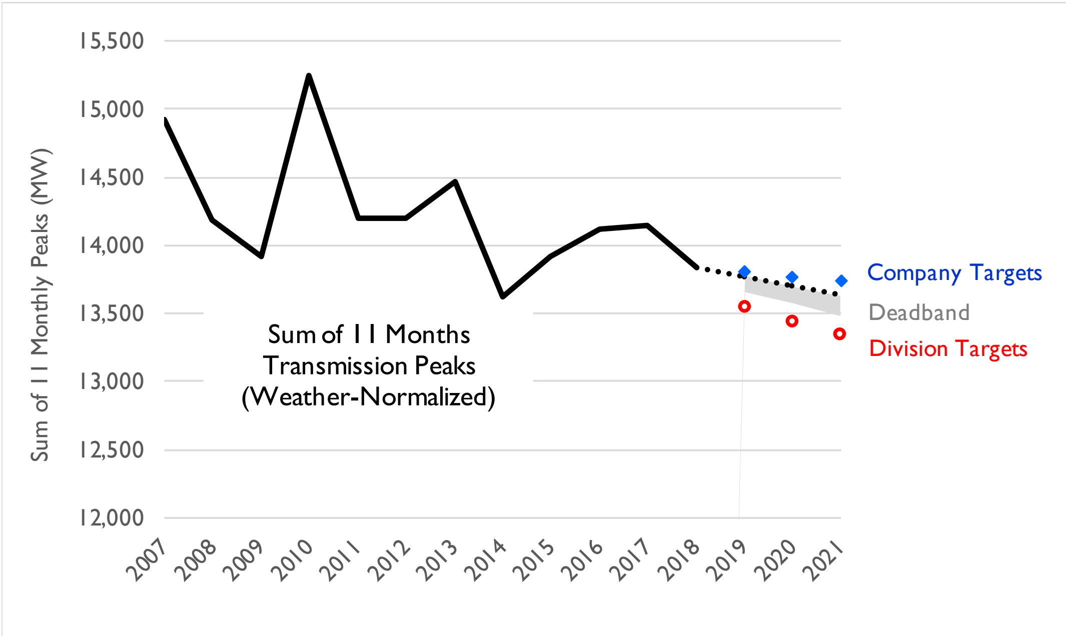
Q. Please describe the Division's proposal for a Transmission Peak Demand Reduction PIM.

A. Company efforts to reduce transmission peak demands could significantly reduce transmission costs and play a foundational role in achieving power sector transformation objectives. Under current ratemaking practice, National Grid has little financial incentive to reduce transmission peak demand, because these costs are entirely passed on to customers. A PIM can help create such an incentive while also creating net benefits to customers.

We propose that the metric for the Transmission PIM be the sum of monthly peak demands for each year, excluding the highest peak month. We exclude the highest month to avoid double-counting, as this month is when the FCM peak demand occurs, and the peak demand reductions in that month will be counted towards the FCM PIM. The 11-month transmission peak demand reduction would be calculated as the difference between a baseline of transmission peaks and the actual transmission peaks. Both the baseline and the actual peaks would be calculated in weather-normalized terms.

We propose that the baseline for the Transmission PIM be the 11-month sum of forecasted weather-normalized peak demand for the year in question rather than year-over-year reductions, as proposed by the Company. The Company's historical transmission peak demand, along with our forecast, proposed deadband, and PIM targets are presented in Figure 3.

Figure 3. Transmission Peak Demands: Historical, Our Forecast, Deadband, and Targets



The Company does not have a weather-normalized transmission peak demand forecast.[10] In addition, the Company has not weather-normalized its historical transmission peak data.[11] Without having weather-normalized historical data or a forecast of future transmission peak demand, it is not possible to set a reasonable target or determine with any certainty whether transmission peak reductions are the result of utility action or some other factor.

In order to develop more reasonable targets for this PIM, we developed a weather-normalized forecast for transmission peaks by regressing 11 years of transmission peak

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[10] Response to (Docket 4770) Division 25-12.

[11] Response to (Docket 4770) Division 25-14

data[12] on various weather variables. We tested for multicollinearity and goodness of fit, and selected the model containing the explanatory variables of cooling degree days (CDD), heating degree days (HDD), and year. The model had an adjusted R^2 of 0.67.

The regression coefficients from this model were then used to create a weather-normalized historical baseline and to forecast a 2019 – 2021 baseline. Once the baseline was constructed, it became apparent that the Company's targets were inadequate, as they lay *above* the forecast, implying that the Company would be rewarded for doing nothing at all.

To create reasonably aggressive targets, a deadband was created by subtracting 0.5 standard errors associated with each prediction for years 2019 – 2021 from that year's weather-normalized baseline. Achieved reductions that lie within the deadband are too small to say with certainty whether utility action had an effect on the reduction.

Similar to the FCM PIM targets, the Division proposes to establish targets for the transmission peak demand PIM at 0.5 standard errors, 1.0 standard error, and 1.5 standard errors for the minimum, medium, and maximum targets, respectively. For clarity, these targets are presented in Table 9 in terms of the sum of 11 months of reductions, and as average monthly MW reductions.

The Company should be compensated only for peak reductions that fall below the deadband, which means that, for example, in year 2019 the Company will need to reduce peak demand by 228 MW beyond the baseline (equivalent to 21 MW on a monthly

[12] Monthly data were collapsed into an annual sum of monthly transmission peaks, excluding the maximum month.

basis). In that year the deadband amount is 114 MW (equivalent to 10 MW on a monthly basis).

We propose that the incentives for the Transmission PIM be equal to 50 percent of the quantified net benefits of the transmission peak reductions achieved. We do not propose any additional basis points for unquantified benefits associated with FCM peak reductions, because we are not aware that there are any. These Transmission PIM incentives are presented in Table 9.

Table 9. Transmission Peak Demand Reduction PIM Summary

Transmission Peak Demand Reduction	2019 (med)	2019 (high)	2020 (med)	2020 (high)	2021 (med)	2021 (high)
Targets (sum of 11 monthly peaks (MW))	228	342	255	383	284	425
Targets (average monthly reduction (MW))	21	31	23	35	26	39
Incentive for Quantified Benefits (bps)	40	80	46	93	51	103
Incentive for Unquantified Benefits (bps)	-	-	-	-	-	-
Total Incentive (bps)	40	80	46	93	51	103

4.5. Division's Proposed Distributed Energy Resource PIMs

Q. Please summarize your rationale for the proposed DER PIMs.

A. There is a wide variety of DERs available today for customers or the Company to take advantage of. The various types of DERs have different levels of commercial development, economic viability, and customer acceptance. Each type of DER is expected to play an important role in power sector transformation over the long-term. Accordingly, we believe it is appropriate to establish at least one PIM at this time for each type of DER.

For some types of DERs, such as C&I demand response and electric heat, the associated initiative and potential benefits are fairly well established and will likely offer significant net benefits between now and the next rate case. For other types of DERs, such as behind-the-meter storage, the associated initiative and potential benefits are not yet well established and thus may have a relatively small impact prior to the next rate case. We recommend establishing at least one PIM for each type of DER, even if the PIM might have a small impact in the short-term, because that sends an important signal to the Company that it should be investigating opportunities for all types of DERs.

Q. Please describe the Division's proposal for a Residential Demand Response PIM.

A. Residential demand response is expected to play an important role in reducing peak demands and helping to achieve power sector transformation objectives. The Company's residential demand response program "Connected Solutions" is in an early phase and does not appear to be cost-effective, based on the data provided by the Company.[13] However, National Grid is developing a more robust program for the 2019 Energy Efficiency Plan. The opportunities for demand response program will expand considerably if and when the Company installs AMF. Therefore, we propose a Residential DR PIM where the incentive is based on shared savings, to encourage the Company to develop a more cost-effective program, and to implement it as efficiently as possible.

We propose that the metric for the Residential DR PIM be equal to the amount of peak demand (in MW) that customers have signed up to reduce through participation in

[13] Response to (Docket 4770) Division 1-39

the Residential DR program. Ideally, the metric would be the actual amount of capacity that was reduced by customers as a result of the program. However, this amount might depend upon the wholesale market prices during peak periods, which are beyond the control of the Company.[14] Instead, we propose that the targets be based on enrolled capacity, but that the Company also provide an annual report regarding the number of events called and the estimated demand reductions achieved each year.

The targets we propose for this PIM are presented in Table 10. These are based on our expectation of the capacity that the Company might enroll through the Residential DR program. The baseline for this PIM is simply zero, because there would be no residential DR without the program.

The incentives we propose for this PIM are presented in Table 10. As indicated in the table, we expect the quantified net benefits to be relatively small due to the relatively small size of the program and our cost assumptions. Once these net benefits are shared equally between the Company and the customers, the amount of the Company's incentive is less than one basis point. We add one basis point incentive targets achieved in each year to reflect the unquantified benefits expected to result from residential demand response programs. These unquantified benefits include improved reliability and the development of markets and products related to residential demand response and home energy management in general. For example, sophisticated thermostats enrolled in the Connected Solutions program can be expected to provide energy savings as well as capacity benefits.

[14] It is possible that demand response events would not be called at all during mild summers.

Table 10. Residential Demand Response: Targets and Incentives

Demand Response – Residential	2019 (med)	2019 (high)	2020 (med)	2020 (high)	2021 (med)	2021 (high)
Targets (incremental MW savings)	1	2	2	3	3	4
Incentive for Quantified Benefits (bps)	-	-	-	-	-	1
Incentive for Unquantified Benefits (bps)	1	1	1	1	1	1
Total Incentive (bps)	1	1	1	1	1	2

Q. Please describe the Division's proposal for a C&I Demand Response PIM.

A. Commercial and Industrial (C&I) demand response is expected to play an important role in reducing peak demands and helping to achieve power sector transformation objectives. The Company's C&I demand response program has been very cost-effective to date.[15] We propose a C&I DR PIM where the incentive is based on shared savings to encourage the Company to expand its C&I DR program cost-effectively.

We propose that the metric for the C&I DR PIM be equal to the amount of peak demand (in MW) that customers have signed-up to reduce through participation in the C&I DR program. Ideally, the metric would be the actual MW reductions provided by customers as a result of the program. However, this amount might depend upon the wholesale market prices during peak periods, which are beyond the control of the Company.

The targets we propose for this PIM are presented in Table 11. These are based on a moderate scaling up of the existing C&I DR program. The baseline for this PIM is simply zero, because there would be no DR contracts with customers without the DR program.

[15] Based on our analysis of response to (Docket 4770) Division 3-14.

The incentives we propose for this PIMs are presented in Table 11. This program is expected to result in a modest amount of net benefits, which lead to incentives based on quantified net benefits of 2 to 3 basis points, increasing to 7 to 11 basis points in later years. Further, given that there are additional unquantified benefits (such as reliability and resiliency and market transformation, particularly with respect to new "smart" devices that help customers manage their demand and energy consumption), we propose that the Company be eligible to earn an additional basis point in incentives for achieving its targets. Thus, the range of total basis points is 3 to 4 bps in 2019 increasing to 8 to 12 basis points in 2021.

Table 11. Commercial and Industrial Demand Response: Targets and Incentives

Demand Response – C&I	2019 (med)	2019 (high)	2020 (med)	2020 (high)	2021 (med)	2021 (high)
Targets (incremental MW savings)	8	14	10	16	12	18
Incentive for Quantified Benefits (bps)	2	3	4	7	7	11
Incentive for Unquantified Benefits (bps)	1	1	1	1	1	1
Total Incentive (bps)	3	4	5	8	8	12

Q. Please describe the Division's proposal for an Electric Heat PIM.

A. Electric heat is a key component of strategic electrification, which advances the goals of increasing energy efficiency and reducing greenhouse gases and other pollutants while lowering costs to customers and society. National Grid estimates that its Electric Heat initiative will be cost-effective, with a benefit-cost ratio of 1.4. [16]

We have developed targets based on the avoided CO_2 emission estimates contained in the Company's benefit-cost analysis for the Electric Heat Initiative.[17] These

[16] Response to (Docket 4770) Division 1-1-3, Attachment DIV 1-1-3.
[17] *Ibid.*

avoided CO_2 estimates are higher than those initially proposed by the Company for this PIM.

In addition to proposing higher targets for this PIM, we propose some modifications to the incentives. Most importantly, we propose a shared savings approach based on 50/50 sharing of net savings. We also add an additional 1 to 2 basis points to reflect unquantified benefits of reliability, market transformation, and low income benefits. The targets and incentives we propose for the Electric Heat PIM are presented in Table 12.

Table 12. Electric Heat Initiative: Targets and Incentives

Electric Heat	2019 (med)	2019 (high)	2020 (med)	2020 (high)	2021 (med)	2021 (high)
Targets (incremental Avoided CO_2)	464	556	580	696	595	714
Incentive for Quantified Benefits (bps)	2	3	3	3	3	3
Incentive for Unquantified Benefits (bps)	1	2	1	2	1	2
Total Incentive (bps)	3	5	4	5	4	5

Q. Please describe the Division's proposal for an Electric Vehicle PIM.

A. Electric vehicles are another key component of strategic electrification. In addition to playing a key role in decarbonization, electric vehicles can save customers money and potentially provide grid services. For these reasons, we support a PIM for electric vehicles.

The Company's has baseline and targets for an electric vehicles PIM are generally reasonable. However, we prefer a metric that is more closely tied to the underlying policy goal of reducing greenhouse gases, rather than simply rewarding higher adoption levels of any type of electric vehicle. Such a metric will provide incentives for the Company to prioritize encouraging adoption of vehicles that reduce the most greenhouse gases. Therefore, we propose to convert the Company's baseline and targets into tons of greenhouse gases using the following methodology:

- The Company's proposed baseline was derived using the forecast growth rate for EV sales in New England from the US Energy Information Administration's Annual Energy Outlook 2017. This growth rate would be applied to actual sales in Rhode Island, as reported by the R.L. Polk Vehicles in Operation data source. This data source reports both battery electric vehicles (BEVs) and plug-in hybrid electric vehicles (PHEVs).
- To convert this baseline into greenhouse gas emissions avoided, we used the Company's assumptions contained in the PST Initiative Benefit Cost Analysis workbook (provided in response to DIV 1-1-3). The Company assumed that its EV initiative would result in an adoption rate of 30% battery electric vehicles and 70% plug-in hybrid electric vehicles. The weighted average quantity of greenhouse gases avoided annually per vehicle was estimated to be 3.5 tons. Multiplying 3.5 tons by the baseline number of EVs provides a baseline in greenhouse gas avoided emissions.
- The Company's targets were set to reflect a 20%, 40%, and 80% improvement over the baseline. We have applied the same improvements to greenhouse gas emissions to develop our proposed targets.

The Company's proposed reporting of performance (using the total number of new registrations in Company service territory during the calendar year based on data from the R.L. Polk Vehicles in Operation data source) would generally remain the same, except the number of each type of vehicle would then be multiplied by its respective assumed emissions avoidance factor. In addition, the Company would be required to report any adoption of fleet vehicles and provide assumed emissions avoidance for those vehicles.

In recognition that electric vehicle adoption is a goal with particularly high importance at this point in time, we have added an additional two basis points for achieving the medium targets and three basis points for achieving the high targets. These additional basis points are warranted given the substantial benefits provided by EVs, and the fact that EVs require a critical mass before the market can be transformed. The targets and incentives we proposed for this PIM are provided in Table 13.

Table 13. Electric Vehicle Initiative: Targets and Incentives

Electric Vehicles	2019 (med)	2019 (high)	2020 (med)	2020 (high)	2021 (med)	2021 (high)
Targets (incremental Avoided CO_2)	557	1,114	757	1,511	1,026	2,051
Incentive for Quantified Benefits (bps)	1	1	1	3	2	4
Incentive for Unquantified Benefits (bps)	2	3	2	3	2	3
Total Incentive (bps)	3	4	3	6	4	7

Q. Please describe the Division's proposal for a Behind-the-Meter Storage PIM.

A. Behind-the-meter electricity storage systems represent a flexible resource that can provide important benefits to customers and the grid, including reducing peak demand costs; reducing peak energy costs; increasing reliability and resilience; supporting distributed generation, especially distributed solar; providing ancillary services; and enabling the integration of high penetrations of renewable energy.

We support the Company's proposal to implement a PIM for incremental MW of installed behind-the-meter storage. However, we propose that the incentives be awarded on a shared-savings basis to encourage the utility to promote cost-effective behind-the-meter storage, and to protect consumers if cost-effective options are not available during this time period.

The targets and incentives we propose for this PIM are provided in Table 14. The targets are slightly lower than those proposed by the Company, because our targets require that the resource be cost-effective. Behind-the-meter storage is only economic if customers have time-varying rates, which first require AMF. We therefore assume that the only behind-the-meter storage that will be developed over the next three years will be by commercial and industrial customers.

While the quantified benefits are expected to be small in this time period, we include some incentive for the unquantified benefits expected from (a) technology and market development, and (b) improved reliability and resilience.

Table 14. Behind-the-Meter Storage Initiative: Targets and Incentives

Behind-the-Meter Storage	2019 (med)	2019 (high)	2020 (med)	2020 (high)	2021 (med)	2021 (high)
Targets (incremental MW)	1	2	1	2	1	2
Incentive for Quantified Benefits (bps)	-	1	1	1	1	2
Incentive for Unquantified Benefits (bps)	1	2	1	2	1	2
Total Incentive (bps)	1	3	2	3	2	4

Q. Please describe the Division's proposal for a Utility-Scale Storage PIM.

A. Utility-scale electricity storage systems represent a flexible resource that can provide important benefits to customers and the grid, including reducing peak demand costs;

reducing peak energy costs; increasing reliability and resilience; supporting distributed generation, especially distributed solar; providing ancillary services; and enabling the integration of high penetrations of renewable energy.

We support the Company's proposal to implement a PIM for incremental MW of installed utility-scale storage. However, National Grid's BCA indicates that utility-scale storage owned by the Company may not be cost-effective over the next three years.[18] Therefore, we recommend expanding this PIM to include any form of utility-scale storage, which could be owned by the Company or purchased from third-party providers. In addition, we propose that the incentives be awarded on a shared-savings basis to encourage the utility to promote cost-effective utility-scale storage, to protect consumers if cost-effective options are not available during this time period.

The targets and incentives we propose for this PIM are provided in Table 15.The targets are the same as those proposed by the Company. In addition to the incentives for quantified net benefits, we include some incentive for the unquantified benefits expected from (a) technology and market development, and (b) improved reliability and resilience.

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[18] *Ibid.*

Table 15. Utility-Scale Storage: Targets and Incentives

Utility-Scale Storage	2019 (med)	2019 (high)	2020 (med)	2020 (high)	2021 (med)	2021 (high)
Targets (incremental MW)	3	6	3	6	3	6
Incentive for Quantified Benefits (bps)	2	5	5	10	8	15
Incentive for Unquantified Benefits (bps)	1	2	1	2	1	2
Total Incentive (bps)	3	7	6	12	9	17

Q. Please describe the Division's proposal for a Non-Wires Alternative PIM.

A. Non-wires alternatives (NWA) include a set of DERs that are applied to a specific location on the grid to address a particular distribution system constraint. NWAs can help reduce distribution, transmission, and generation capacity costs, as well as help promote the deployment of new DER technologies. National Grid has implemented a pilot NWA project as part of the System Reliability and Procurement process since 2012, in the towns of Tiverton and Little Compton. In 2018 the Commission approved a PIM for the Tiverton-Little Compton NWA, which requires the Company to issue at least one RFP for vendors to provide bids for NWA projects. The Company will be allowed to keep a portion of the net benefits of any projects that are implemented as part of that effort.[19]

We propose to continue the existing NWA PIM for the next three years. Competitive bidding among third-party vendors creates an opportunity to identify cost-effective alternatives to distribution system needs that might not be identified by National Grid. We propose to continue the shared-savings approach used in the 2018 SRP to encourage the Company to seek the most cost-effective options, and to protect consumers if cost-effective options are not available during this time period.

[19] Cite 2018 SRP.

The targets and incentives we propose for this PIM are provided in Table 16. The targets are based on our assessment of the potential NWA savings that might be available in the next three years. In addition to the incentives for quantified benefits, we include some incentive for the unquantified benefits expected from technology and market development.

Table 16. Non-Wires Alternatives: Targets and Incentives

Non-Wires Alternatives	2019 (med)	2019 (high)	2020 (med)	2020 (high)	2021 (med)	2021 (high)
Targets (incremental MW)	3	6	3	6	3	6
Incentive for Quantified Benefits (bps)	1	2	2	3	3	5
Incentive for Unquantified Benefits (bps)	1	2	1	2	1	2
Total Incentive (bps)	2	4	3	5	4	7

4.6. Division’s Proposed Power Sector Transformation Support PIMs

Q. Please summarize your rationale for the Power Sector Transformation Support PIMs.

A. We propose two PIMs to help protect low-income customers. The first is to encourage National Grid to increase low-income customer participation in all of the PST initiatives. The second is to encourage National Grid to increase the percent of low-income customers that are enrolled in the A60 low-income discount rate. These PIMs are important to enable low-income customers to enjoy the direct benefits of PST initiatives, and to protect them from potential rate increases.

We also propose two PIMs to encourage the Company to provide customer information and improve its distribution demand forecasting practices. These PIMs can be described as “action-based,” because they are focused on specific actions that the

Company can take to achieve desired outcomes. This type of PIM is different from outcome-based or program-based PIMs in that there may not be direct monetary benefit or net benefit associated with the action. Instead, the action is presumed to lead to other actions or outcomes that will provide net benefits to customers. Action-based PIMs are appropriate to encourage a utility to take steps that are foundational to power sector transformation objectives, but that the utility is unlikely to take without the PIM. Often this type of PIM is only necessary for a short time, to help facilitate a transition.

Q. Please describe the Division's proposal for a Low-Income PST Participation PIM.

A. Customers who participate in one of the Company's DER programs will experience direct benefits in terms of bill reductions. It is especially important to enroll low-income customers in such programs, to make their electricity bills more affordable. When a low-income customer's bill is more affordable they are more likely to pay their bills, which will reduce the bill arrearages that all customers pay for. Reduced low-income consumption and bills can also help reduce the amount of money that is used to pay for the low-income discount rate, which is also paid for by all customers.

We propose that the metric for the LI Participation PIM be the percent of low-income customers enrolled in any one of the Company's DER programs, including demand response, electric heat, electric vehicles, and electric storage. We exclude the Company's energy efficiency program from this PIM, because the Company already has a long history of promoting low-income energy efficiency programs.

The baseline for this PIM should be the percent of low-income customers relative to total residential customers.

The targets for this PIM should be based on DER program participation rates relative to the baseline percentage of low-income customers. We propose a medium target equal to a program participation rate that is five percent higher than the baseline percentage of low-income customers. Thus, if the baseline percentage is 15 percent, the medium target should be 20 percent participation of low-income customers in the relevant DER programs. For this calculation of program participation rate, low-income participation in all of the relevant DER programs can be combined. We propose the high target for this PIM equal to a program participation rate that is ten percent higher than the baseline percentage of low-income customers.

The low-income participation PIM does not have any benefits that can be readily quantified. Therefore, we propose an incentive based upon the unquantified benefits of improving low-income customer affordability and reducing utility arrearages. The targets and incentives we propose for this PIM are provided in Table 17.

Table 17. Low-Income PST Participation PIM: Targets and Incentives

Low Income PST Participation	2019 (med)	2019 (high)	2020 (med)	2020 (high)	2021 (med)	2021 (high)
Targets (percentage point increase)	5	10	5	10	5	10
Incentive for Quantified Benefits (bps)	-	-	-	-	-	-
Incentive for Unquantified Benefits (bps)	2	3	2	3	2	3
Total Incentive (bps)	2	3	2	3	2	3

Q. Please describe the Division's proposal for a Low-Income Discount PIM.

A. The low-income discount is an important mechanism for not only reducing the energy burden of this important customer group, but also for enabling more low-income customers to pay their bills thereby reducing the Company's arrearages. Mr. Colton addresses the Division's proposal for modifications to the Company's low-income discount.

We propose establishing a PIM to encourage National Grid to increase the number of low-income customers that are on the low-income, A60 discount. The metric for this PIM would the percentage of total low-income customers that are on the A60 discount. The baseline would be the average of the low-income discount participation percentage for the previous five years.[20]

The low-income discount PIM does not have any benefits that can be readily quantified. Therefore, we propose an incentive based upon the unquantified benefits of improving low-income customer affordability and reducing utility arrearages. The targets and incentives we propose for this PIM are provided in Table 18.

Table 18. Low-Income Discount PIM: Targets and Incentives

Low Income Discount	2019 (med)	2019 (high)	2020 (med)	2020 (high)	2021 (med)	2021 (high)
Targets (percentage point increase)	4	8	4	8	4	8
Incentive for Quantified Benefits (bps)	-	-	-	-	-	-
Incentive for Unquantified Benefits (bps)	2	3	2	3	2	3
Total Incentive (bps)	2	3	2	3	2	3

Q. Please describe the Division's proposal for a Data Access PIM.

A. In order to fully enable increasing amounts or DERs and increasing levels of third-party activities, it will be necessary to provide customers and third-parties with access to key system data. This includes data on customer electricity consumption patterns and data regarding the operation and the constraints on the distribution system.

[20] For example, the baseline for 2021 would be the average participation percentage for 2016-2020.

We propose establishing a PIM to encourage National Grid to develop customer and third-party data access plans. The target would be to submit to the Commission the first annual Customer and Third-Party Data Access plan by July 2019. This plan should be developed in coordination with the Division and other stakeholders, and should comply with the relevant data access recommendations in the RI PST Report.[21]

The Data Access PIM does not have any benefits that can be readily quantified. Therefore, we propose an incentive based upon the unquantified benefits of providing important foundational support for power sector transformation. The incentives we propose for this PIM are provided in Table 19.

Table 19. Data Access: Targets and Incentives

Data Access	2019 (med)	2019 (high)	2020 (med)	2020 (high)	2021 (med)	2021 (high)
Target	Plan	-	-	-	-	-
Incentive for Quantified Benefits (bps)	-	-	-	-	-	-
Incentive for Unquantified Benefits (bps)	1	-	-	-	-	-
Total Incentive (bps)	1	-	-	-	-	-

Q. Please describe the Division's proposal for a Peak Demand Forecasting PIM.

A. As the roles of DERs, third-parties, and active customers expand over time, it will be increasingly important for National Grid to improve its practices for forecasting distribution peak demand. The Company's forecasts will need to incorporate better information regarding where, and what kind, of DERs are being installed and are expected to be installed on its system. In the absence of detailed estimates regarding reduced (or increased) demand from DERs, the Company will over-build (or under-build)

[21] The RI PST Report, pp. 49-53.

its distribution system, resulting in excess costs, insufficient reliability, or both. Information on the geographical location of new DERs will be necessary in order to fully forecast distribution constraints and optimize its distribution investments.

We propose establishing a PIM to encourage National Grid to improve and expand upon its current forecasting practices. The target would be to submit to the Commission by July 2019 a Peak Demand Forecasting Report. This report should be developed in coordination with the Division and other stakeholders, and should comply with the relevant forecasting recommendations in the RI PST Report.[22]

The Peak Demand Forecasting PIM does not have any benefits that can be readily quantified. Therefore, we propose an incentive based upon the unquantified benefits of providing important foundational support for power sector transformation. The targets and incentives we propose for this PIM are provided in Table 20.

Table 20. Peak Demand Forecasting: Targets and Incentives

Peak Demand Forecasting	2019 (med)	2019 (high)	2020 (med)	2020 (high)	2021 (med)	2021 (high)
Target	Report	-	-	-	-	-
Incentive for Quantified Benefits (bps)	-	-	-	-	-	-
Incentive for Unquantified Benefits (bps)	1	-	-	-	-	-
Total Incentive (bps)	1	-	-	-	-	-

[22] The RI PST Report, pp. 48-49.

4.7. Process for Reviewing PIMs and Recovering Incentives

Q. Please describe how the Commission should review the PIMs approved in this docket.

A. We recommend that the Commission direct National Grid to submit annual Performance Incentive Mechanism Plans, to provide all the information needed to establish the PIMs that will commence in the following calendar year. The submission and review of the annual PIM Plans should be coordinated and contemporaneous with the annual Energy Efficiency and System Reliability and Procurement Plans. Both plans should be submitted by October 31 each year, and subsequently reviewed by the Commission to be implemented in the following year.

For the first PIM Plan, the Commission should direct National Grid to submit it by November 31, 2018, in order to allow time for preparation after the order in this docket is issued. That first PIM Plan should include updated PIM proposals based upon all the Commission's ultimate findings in this docket. It should include updated metrics, targets, baselines, and incentives using the methodologies and assumptions directed by the Commission. The incentives would be based on updated benefit-cost analyses, using the most recently available New England Avoided Energy Supply Cost study, and related findings by the Commission.

The Commission should open a docket to review and make findings on the first PIM Plan. Given the importance of the first PIM Plan, we recommend that the Commission allow for full stakeholder input to its review, including adjudicative hearings. The Commission should allow several months for review of this first PIM Plan, which means that the PIMs might not be approved by the Commission until March of

2019. The Company should nonetheless begin working to achieve the PIM targets in January of 2019, based on the direction provided by the Commission in the order in this docket.

Q. Please describe how the Company should report information related to the PIMs to the Commission.

A. We recommend that National Grid file with the Commission an annual Performance Report, which would include all relevant information on the metrics, targets, and incentives earned for the period covering the previous calendar year. This report should be filed in the third quarter of the year following the relevant performance year, in order to allow time to collect and verify the relevant information. The submission and review of the annual Performance Reports should be coordinated and contemporaneous with the annual Energy Efficiency and System Reliability and Procurement Plans.

The annual Performance Report should include information on every PIM that applies to National Grid, including the Service Quality PIMs, the Energy Efficiency PIMs, all the PIMs created in this rate case (Docket 4770), and any remaining SRP PIMs. The reports would include information on the metrics for the most recent five years, to the extent that the data is available, to provide an indication of performance trends over time. The reports would also include information on the deviations between targets and actual values.

National Grid should also file with the Commission streamlined versions of the annual Performance Report on a quarterly basis, similar to how the Company currently submits quarterly reports for its energy efficiency activities. The quarterly reports are useful for monitoring whether the Company is roughly on track to meet its targets, and to determine whether any mid-year corrections might be necessary.

Q. Please describe when and how the Company's rates would be adjusted to provide the Company with the PIM incentives.

A. Once an annual Performance Report has been approved by the Commission, the Company's rates should be adjusted to account for amount of incentives earned by the Company. The PIM incentive rate adjustments should occur once per year and should occur at the same time as the decoupling and energy efficiency rate adjustments, in order to streamline the regulatory process and minimize the number of times within the year that rates are adjusted.

4.8 The Mechanics of the Earnings Sharing Mechanism

Q. Please describe the earnings sharing mechanism that is currently in place.

A. Currently, the Company's earnings are subject to an earnings sharing mechanism, under which the Company must file annual reports calculating the Company's return on equity for the prior calendar year. This mechanism was established in Docket 4323. An earnings report is filed for both the electric and gas businesses separately and calculates the earned return on common equity (ROE) including and excluding any incentives earned under the energy efficiency program. If the Company's earned ROE is greater than the allowed ROE, the Company shares the over-earnings with ratepayers 50/50 until excess earnings reach 100 basis points over the allowed ROE. Any excess earnings in excess of 100 basis points over the allowed ROE is shared 75/25 in favor of ratepayers. Whether or not the energy efficiency incentive would be taken into account was not specified. However, since the current mechanism was put in place, the Company has not exceeded its allowed ROE, as measured by any of the filed reports in that Docket. For that reason, the question of the applicability of the energy efficiency was never addressed.

Q. What is the Division proposing in this case?

A. In this case, the Division recommends that an earnings sharing mechanism remain in place, measured against the allowed ROE established by the Commission in this Docket. However, the Division recommends some important changes to the mechanism applying to electric side of the business that will work in conjunction with the PIMs.

Q. Please explain how the earnings sharing mechanism would work.

A. Similar to today's mechanism, the Company would be required to file annual earnings reports for both electric and gas. The gas earnings report should contain the same information and operate the same as it is operating today, with the same sharing of excess earnings as designated in Docket 4323. However, for the electric earnings report, the reports should calculate the earnings with and without any PIMs awards from the prior calendar year in order to show the Commission the effect of the PIMs on the Company's performance. The operation of the electric earnings sharing mechanism would also be different. Specifically, to the extent the Company has earned over its allowed ROE, the Company would be able to retain 100% of all earnings up to 100 basis points over the allowed ROE. Once the excess earnings exceed 100 basis points, however, the amount of excess earnings above 100 basis points would be shared 75/25 in favor of ratepayers. All PIMs earned on the electric side of the business should be counted in the calculation of the overearnings, including the energy efficiency incentive and any new PIMs approved by the Commission. The earnings sharing mechanism will assure that the new PIMs programs, in conjunction with the existing energy efficiency incentive, will not result in excessive earnings. At the same time, since there is a sharing of any excess over 100 basis points, ratepayers are protected.

Q. Why are you recommending that 100% of the earnings be retained by the Company up to 100 basis points?

A. This is an important change from the current mechanism in light of the incentives the Division is proposing in this case. It is consistent with the recommendation to set the allowed ROE at the lower end of the cost of equity range. By achieving the PIMs targets, the Company has the opportunity to grow its earnings from the lower end of the range upward. However, by setting a sharing point after 100 basis points that triggers a 75/25 sharing with ratepayers, it provides an important and significant incentive to the Company, while at the same time protecting ratepayers from excessive earnings.

5. NATIONAL GRID'S PERFORMANCE INCENTIVE MECHANISM

5.1. National Grid's Proposal

Q. Why has the Company proposed PIMs?

A. National Grid notes that it has developed PIMs to advance Rhode Island's energy policy goals, provide new benefits to customers, and reward utility performance in delivering key programs.[23] The Company claims that the current regulatory framework "is not sufficient to drive innovative utility performance," and that new compensation

[23] PST Panel Direct Testimony, p. 81, lines 15-19.

mechanisms are needed to align utilities' "financial interests with broader policy goals and customer outcomes that expand beyond core performance obligations."[24]

Q. What type of PIMs has the Company proposed?

A. National Grid has proposed four types of PIMs: capital efficiency, system efficiency, DER, and network support service PIMs.

Q. What are the Company's proposed PIMs based on?

A. National Grid states that it considered the PIM recommendations in the Power Sector Transformation Report. The Company views the PIMs proposed in this docket as a "first step in a broader evolution of the regulatory framework," suggesting that the proposed PIMs could be modified or expanded over time.[25] National Grid also followed several principles in designing its PIMs, as described in Section 4.3

Q. Does National Grid already have PIMs in place today?

A. Yes. Since 1990 the Company has had a shareholder incentive mechanism for its energy efficiency programs. The energy efficiency PIM was developed through negotiations with the Company in the DSM Collaborative, and it has been modified several times in the past. National Grid also has a set of PIMs related to its service quality plans. The Company is also allowed to earn shareholder incentives for long-term renewable contracts, distributed generation contracts, and the Renewable Energy Growth program, as determined by legislation.

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[24] PST Panel Direct Testimony, p. 83, lines 9-14.
[25] PST Panel Direct Testimony, p. 84, lines 1-9.

Q. Does National Grid's proposal for new PIMs include any penalties for underperformance?

A. No. All of the PIMs proposed by the Company include only rewards for performance related to the relevant targets. National Grid notes that the reward-only PIMs are appropriate because they are related to new customer benefits, and they "reflect new areas of accountability for the Company that expand beyond its core obligations."[26]

Q. Please summarize the capital efficiency PIMs proposed by National Grid.

A. The Company has proposed two capital efficiency PIMs:

- The Complex Capital Projects Capital Cost Incentive. The Company is proposing to compare actual final capital costs to a baseline estimate of capital costs that were used to review and approve the project. Any savings relative to the baseline would be shared equally between customers and shareholders, and any costs above the baseline would be borne by the Company's shareholders.
- The Construction Costs per Mile Productivity Incentive. The Company has not fully developed this metric. National Grid plans to develop a metric based on the construction cost per mile for distribution projects. The Company notes that it will propose a baseline and targets for this PIM in its FY 2020 Electric ISR Plan filing.[27]

Q. Please summarize the System Efficiency PIMs proposed by National Grid.

A. National Grid's proposed System Efficiency PIMs are summarized in Table 21.[28]

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[26] PST Panel Direct Testimony, January 12, 2018, page 85, lines 4-9.
[27] PST Panel Direct Testimony, January 12, 2018, page 86, lines 10-14.
[28] PST Panel Direct Testimony, January 12, 2018, Redlined Tariff Sheet 15 (Bates 18)

Table 21. Company's Proposed System Efficiency PIMs

PIM	Description	2019 Med Incentive (bps)	2019 Max Incentive (bps)
FCM Peak Demand Reduction	Reduce annual FCM peak hour demand (weather-normalized). Baseline is 2018 FCM peak.	12	18
Transmission Peak Demand Reduction	Reduce monthly transmission peak demands. Baseline is sum of 11-months of 2018 transmission peaks.	1.75	2.5
Off-Peak Charging Rebate Pilot	Pilot program to encourage customers to charge EVs during off-peak hours. Baseline is the assumed participation rates.	2.5	3.0
Total	----------------------	**16.25**	**23.5**

Q. Please provide additional details on the FCM Peak Demand Reduction PIM proposed by National Grid.

A. The purpose of the FCM Peak Demand Reduction PIM is to encourage the Company to reduce the annual forward capacity market (FCM) peak demand to reduce Narragansett Electric's share of annual FCM costs. The metric for this PIM will be the weather-normalized FCM peak demand. The baseline for this PIM is the actual weather-normalized FCM peak demand of the previous year, beginning with 2018. The Company's proposed MW targets are presented in Table 22.[29]

Table 22. The Company's Proposed FCM PIM Targets

FCM PIM	2019 Target (med)	2020 Target (med)	2021 Target (med)
Metric: Weather-normalized annual FCM peak capacity reduction (MW) relative to previous year.	29	26	26

[29] PST Panel Direct Testimony, January 12, 2018, Redlined Tariff Sheet 15 (Bates 18)

These annual FCM targets include the savings that the Company expects to achieve through energy efficiency, distributed generation, volt-var optimization (VVO), and storage.[30] Consequently, the MW savings targets for the FCM PIM only represent additional savings of 5 to 6 MW each year.

Q. Please provide additional details on the Transmission Peak Demand Reduction PIM proposed by National Grid.

A. The purpose of the Transmission Peak Demand Reduction PIM is to encourage the Company to reduce monthly transmission peaks to reduce Narragansett Electric's share of monthly transmission costs. The metric for this PIM is the sum of monthly weather-normalized transmission peak demand. It is unclear whether the Company intends for these values represent the sum of 11 months of transmission peaks or 12 months of transmission peaks. In response to DIV 3-9 (e), the Company states that "to avoid double counting, the Company did not attribute any capacity savings from the month where the annual peak occurs to the Monthly Peak Demand Reduction metric." However, in response to DIV 8-14 (d), the Company states that its proposal for the Monthly Transmission Peak Demand metric is the "annual sum of 12 months peak demands, inclusive of the maximum month. These targets are intended to capture additional incremental effort by the Company to reduce peak demand outside of the annual peak month."

The Company proposes that the baseline for this PIM will be the sum of the actual weather-normalized transmission peak demands in the previous year. This means that the

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[30] Attachment DIV 25-5.

Company's proposed MW savings targets in 2019 are relative to the transmission peak values in 2018, while the savings achieved in 2020 are relative to the transmission peak values in 2019. The Company's proposed MW targets and basis point incentives for this PIM for 2019 are presented in Table 23.[31]

Table 23. The Company's Proposed Transmission PIM Targets

Transmission Peak Demand Reduction PIM	2019 Target (med)	2020 Target (med)	2021 Target (med)
Metric: sum of monthly of transmission peak capacity savings (MW), year-over-year	29	26	26

Q. Please summarize the DER PIMs proposed by National Grid.

A. National Grid's proposed DER PIMs are summarized in Table 24.[32]

[31] PST Panel Direct Testimony, January 12, 2018, Redlined Tariff Sheet 15 (Bates 18)

[32] PST Panel Direct Testimony, January 12, 2018, Redlined Tariff Sheet 16-17 (Bates 19-20)

Table 24. The Company's Proposed DER PIMs

DER PIM	Description	Med Incentive (bps)	Max Incentive (bps)
DG Friendly Substations	The number of substations that have ground fault detection (3V0) installed and that are capable of readily installing DG where significant amounts of DG have been proposed	6	10
Demand Response: Residential	Measured by the number of residential customers participating in the Company's Connected Solutions program.	3	5
Demand Response: C&I	Measured by the contracted MWs in the Company's C&I demand response programs.	3	5
Electric Heat	Measured reductions in carbon in short tons per year.	1	2
Electric Vehicles	EV ownership, measured by EVs registered after commencement of program, in excess of projections based on Annual Energy Outlook 2017 forecast EV sales growth for New England.	2	3.5
Behind the Meter Storage	Measured by the annual MW growth in energy storage installed at customer locations behind a meter used to register electric load.	1	2
Company-Owned Storage	Measured by the installed MW of Company-owned in energy storage, inclusive of the ESS Program above, used to support peak load reduction and verified using interval metering.	1	2
Total	**----------------------**	**17**	**29.5**

Q. Please summarize the network support services PIMs proposed by National Grid.

A. National Grid's proposed network support services PIMs are summarized in Table 25.[33]

[33] PST Panel Direct Testimony, January 12, 2018, Redlined Tariff Sheet 17-18 (Bates 20-21)

Table 25. The Company's Proposed Network Services PIMs

Network Support PIM	Description	Med Incentive (bps)	Max Incentive (bps)
AMF Customer Engagement and Deployment	Measured based on achievement of stated milestones with documentation evidencing achievement provided by the Company. Basis points vary by year.	1 to 2	1 to 2
VVO Pilot Delivery	Project in service; delivery of expected results of VVO deployment measured by a 1 percent reduction in energy consumption and peak demand from that expected from primary VVO optimization that would not include AMF technology of 3 percent	2	2
Interconnection Support: Time to ISA	The actual average time to provide executable Interconnection Service Agreements, measured from the date on which the Company receives the interconnection application to the date the ISAs are provided to customers for execution, during a calendar year, against total time allowed in the required time frames identified in the Company's Standards for Interconnecting Distributed Generation tariff, stated as a percentage.	4	6
Interconnection Support: Average Days to System Modification	The actual average time to complete system modifications, measured from the date ISAs are executed to the date on which system modifications are completed, during a calendar year, against total time allowed in the required time frames identified in the Company's Standards for Interconnecting Distributed Generation tariff, stated as a percentage.	4	6
Interconnection Support: Estimate versus Actual Costs	The difference, measured as a percentage, between the sum of the costs estimated by the Company for interconnecting DG, during a calendar year, and the sum of the actual costs paid by those customers for the interconnection of DG where interconnection was completed in the same calendar year.	4	6
Total	**------------------**	**15 to 16**	**21 to 22**

Q. Please summarize the total incentives that National Grid could potentially earn in 2019 from all its proposed PIMs.

A. These are summarized in Table 26.

Table 26. Incentives that National Grid Could Potentially Earn (bps)

Type of PIM	2019 (med)	2019 (max)	2020 (med)	2020 (max)	2021 (med)	2021 (med)
System Efficiency	16.25	23.25	16.25	23.25	16.25	23.25
Distributed Energy Resources	17.0	29.5	17.0	29.5	17.0	29.5
Network Support Services	16.0	22.0	15.0	21.0	15.0	21.0
Total	49.25	74.75	48.25	73.75	48.25	73.75

5.2. Critique of National Grid's Proposal

Q. Please describe your concerns with National Grid' proposed Capital Efficiency PIMs.

A. Our primary concern with these PIM is that they are not necessary. As described in the direct testimony of Mr. Woolf, the Division recommends that the Commission establish a multi-year rate plan. Under this proposal the Company would automatically have a financial incentive to reduce capital costs and improve productivity between rate cases. In fact, this is one of the primary reasons for establishing an MRP. In the event that this case does not yield an MRP, we offer alternative approaches for encouraging efficient use of capital costs and improved productivity, as described in the direct testimony of Mr. Woolf.

We are also concerned that these PIMs could place too much risk on the customers. The Company would determine the initial capital costs used to set the targets, and therefore has an incentive to overstate cost projections.

Q. Please describe your concerns with National Grid's proposed FCM Peak Demand Reduction PIM.

A. We have concerns regarding the baseline, targets, and incentives associated with National Grid's proposed FCM PIM. First, National Grid proposes to reduce peak demand on a year-over-year basis. These targets were developed in relation to a baseline forecast of peak demand, but converting them to year-over-year targets divorces them from the baseline, rendering it meaningless.[34] The use of a sound baseline in setting and measuring targets is critical, as it captures the effects of many other drivers of peak demand reductions. If these other factors are not accounted for in setting and measuring PIM targets, then the Company might be rewarded for peak demand reductions that are not a result of its actions (or not rewarded despite utility actions that successfully reduce FCM peak demand.)

Second, the Company did not propose targets that provide a sufficient degree of certainty that they will be achieved due to Company effort, rather than other factors. When a forecast is used as a baseline for a PIM, it is often appropriate to establish a "deadband" around the forecast. A deadband is a region around the target within which the Company would not earn a reward (or incur penalties). The concept of a deadband is often used to account for uncertainty regarding the target or to allow for some deviation from the target due to factors outside of utility control.[35] Setting PIM targets outside of a

[34] A consequence of this would be that the same total rewards could be earned over the three year period for varying levels of cumulative peak demand reductions. Suppose, for example, that the Company increased peak demand in the first year artificially, followed by achieving "high" reductions the following two years, which would be easier to achieve. Because the PIM has no penalty for under-performance in year 1, the same rewards could be earned through this method, even though the cumulative reductions would be lower than if the Company had achieved the medium target each year.

[35] Synapse Energy Economics, *Utility Performance Incentive Mechanisms: A Handbook for Regulators.*

deadband helps to ensure that the utility is not provided incentives for outcomes that it is not responsible for.

The Company's FCM peak forecast, along with our proposed deadband and PIM targets are presented in Figure 2, in Section 4.4. The figure indicates that the Company's proposed FCM PIM targets for 2019 and 2020 fall within our estimate of a reasonable deadband, suggesting that the Company could be rewarded for FCM peak reductions that would have occurred in the absence of the PIM or the utility actions. In sum, the Company's proposal would result in PIM targets that have a reasonable likelihood of being achieved without any additional effort by the Company.

Q. Please describe your concerns with National Grid's proposed Transmission Peak Demand Reduction PIM.

A. We have concerns regarding the baseline, the targets, and the incentives associated with National Grid's proposed Transmission PIM. As described above, we do not agree with using the year-over-year reductions in demand as the metric for the transmission peak reduction targets. Performance should be measured relative to a forecast baseline. The use of a sound baseline in setting and measuring targets is critical, as it captures the effects of many other drivers of transmission peak demand reductions. If these other factors are not accounted for in setting and measuring PIM targets, then the Company might be rewarded for peak demand reductions that are not a result of its actions

This is the same problem described above for the FCM PIM. However, unlike the FCM peak demands, the Company does not have a forecast of monthly transmission peak demands.[36] In order to be able to properly evaluate the proposed Transmission PIM, we have prepared our own transmission peak forecast, using historical data provided by the Company.

Our analysis shows that the historical transmission peak demands have been trending downward, and this trend is likely to continue. If the transmission peak reduction targets are based on the 2018 historical peak demand, then the Company could be rewarded for peak reductions that would have occurred without the Transmission PIM and without utility actions.

As noted above, it is often appropriate to establish a "deadband" around the forecast within which there would be no reward or penalties for performance. Deadbands are useful for mitigating uncertainty regarding the target and to allow for some deviation from the target due to factors outside of utility control.[37] PIM targets should be designed to fall outside of such a deadband, to ensure that the utility is not provided incentives for outcomes that it is not responsible for.

The Company's historical transmission peak demand, along with our forecast, proposed deadband, and PIM targets are presented in Figure 3, in Section 4.4. As indicated in the figure, the Company's proposed Transmission PIM targets for 2019 and 2020 fall above our forecast and our estimate of a reasonable deadband, suggesting that the Company could be rewarded for transmission peak reductions that would have occurred in the absence of the PIM or the utility actions. In sum, the Company's proposal to use a historical year for the baseline, instead of a reasonable forecast, has resulted in

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[36] Response to (4770) Division 25-14

[37] Synapse Energy Economics, *Utility Performance Incentive Mechanisms: A Handbook for Regulators.*

Transmission PIM targets that might be so easy to meet that they will not provide any benefits to customers.

In addition, we do not agree with the way that National Grid determined the magnitude of the incentive associated with the Transmission PIM. Because the Company does not have estimates for monthly demand reductions from other initiatives, the Company's proposal appears to allow it to earn financial incentives under this PIM as a result of the energy efficiency, distributed generation, and other PST initiatives that have their own PIMs. This would result in the Company earning PIM incentives twice; once for the Transmission PIM and once for the other PIMs that result in transmission peak reductions.

Q. Please describe your concerns with National Grid's proposed Off-Peak Charging Rebate Pilot PIM.

A. In general, we agree with the Company's goal of encouraging customers to charge their EVs during off-peak hours, and that this could be an important way to transition EV customers to TVR in the future. However, we do not think that participation in Off-Peak Charging Rebate Pilot is a very robust metric for this purpose. Customer participation in the rebate program does not necessarily mean that customers will change their charging patterns.

In addition, we are not convinced that the Company's proposed pilot is the best way to promote the cost-effective adoption of EVs.[38] We prefer an EV metric that is more

[38] Our concerns about the Company's proposed Electric Vehicle initiative are described in our testimony in Docket 4780.

closely tied with one of the primary objectives for promoting EVs: the reduction of greenhouse gases.

Q. Please describe your concerns with National Grid's proposed Distributed Energy Resource PIMs.

A. Our concerns with National Grid's proposed DER PIMs are summarized below:

- DG-Friendly Substation Transformer. It is our impression that National Grid should be installing ground fault detection (3VO) at substation transformers in a timely fashion as part of its core performance obligation. Installation of these technologies is now common practice for the Company, and National Grid does not require a PIM to encourage better or timelier performance in meeting its obligations.
- Demand Response: Residential. The number of customers participating in the program is not a good metric for demand response programs, because it does not directly reflect the outcome desired, which is the ability to reduce demand during peak hours. We prefer a metric that reflects the number of MW that the Company has contracted customers to provide during peak hours. In addition, we prefer that the magnitude of the incentive be based on a shared savings approach; which will encourage the Company to design and implement programs in the most cost-effective way, and will protect customers in the event that the demand response program net benefits are small or negative.
- Demand Response C&I. We prefer that the magnitude of the incentive be based on a shared savings approach; which will encourage the Company to design and implement programs in the most cost-effective way, and will protect customers in the event that the demand response program net benefits are small or negative.
- Electric Heat Initiative. We prefer that the magnitude of this incentive be based on a shared savings approach. This will encourage the Company to design and implement programs in the most cost-effective way, and will protect customers in the event that the initiative's net benefits are small or negative.

- Electric Vehicles. One of the primary policy goals for promoting EVs is to reduce greenhouse gas emissions. Therefore, we prefer a metric that is more directly tied to this policy goal.
- Behind-the Meter Storage. We are concerned that the Company's behind-the-meter storage program is not sufficiently defined at this time. Also, for the many customers that do not have time-varying rates, behind-the-meter storage is not likely to be economical. Even for those customers with TVR, the Company has not demonstrated that behind-the-meter storage will provide net benefits to customers. We prefer that the magnitude of any incentive be based on a shared savings approach; which will encourage the Company to design and implement a program in the most cost-effective way, and will protect customers in the event that the program net benefits are small or negative.
- Company-Owned Storage. We are concerned that the Company-Owned Storage PIM is not justified on economic grounds. The Company's BCA indicates that company-owned storage has a benefit-cost ratio of 0.45.[39] In addition, we prefer that the magnitude of any incentive be based on a shared savings approach; which will encourage the Company to design and implement a program that is cost-effective, and will protect customers in the event that the program net benefits are small or negative.

Q. Please describe your concerns with National Grid's proposed Network Support Services PIMs.

A. In general, we are concerned that all of the Company's Network Support Services PIMs are not justified because they are for activities that National Grid should undertake anyway. In particular:

- AMF Customer Engagement and Deployment. This PIM is premature, given that the Commission has not yet approved system-wide deployment of AMF.

[39] Schedule PST-1, Chapter 7, Energy Storage, page 6 of 9.

- VVO Pilot Delivery. The Company has clearly demonstrated that VVO will improve the efficiency with which the electricity grid is operated and provide significant net benefits to customers.[40] While VVO technologies might be described as relatively new, they fall within the Company's core performance obligations, and thus do not warrant a PIM. In addition, VVO technologies are not necessarily foundational to power sector transformation.

- Interconnection Support – Time to ISA. The Company already has a legislative requirement and performance standards to complete certain aspects of the interconnection process for distributed generation in a timely fashion.[41]

- Interconnection Support – Estimate Versus Actual Cost. Interconnecting distributed generation customers at a reasonable, low cost is already a part of the Company's core performance obligations, and thus does not warrant a PIM.

6. NEW GRID MODERNIZATION INVESTMENTS

6.1. National Grid's Proposal

Q. Please describe National Grid's proposal for new grid modernization investments.

A. The Company has submitted a request for approval of several projects intended to enable the adoption and interconnection of higher levels of DER. National Grid introduces these projects in Schedule PST – 1, Chapter 3 of its initial filing, and addresses them further in Section V.a in the PST Panel testimony in Docket 4780. The Company sometimes refers to these investments as "new grid modernization activities," and sometimes as "DER enabling investments." These investments cover a variety of distribution system

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40 Response to (4770) Division 3-20, Attachment DIV 3-20.

41 See, RI Gen L § 39-26.3-3 (2012): Upon receipt of a completed application requesting a feasibility study and receipt of the applicable feasibility study fee, the electric distribution company shall provide a feasibility study to the applicant within thirty (30) days. Upon receipt of a completed application requesting an impact study and receipt of the applicable impact study fee, the electric distribution company shall provide an impact study within ninety (90) days.

upgrades, including those related to: a system data portal; feeder monitoring sensors; control center enhancements; operation data management; telecommunications; and cybersecurity.[42]

Q. Please explain why the Company's proposed new grid modernization investments are relevant to this rate case docket.

A. While National Grid's proposal for new grid modernization projects was included as part of Docket 4780, there are two categories of those projects that would impact the revenue requirements in this rate case docket. First, the Company proposes to move forward with a multi-jurisdictional deployment of its GIS Data Enhancement project and include some of the new grid modernization investments, ranging from $0.43 million it its revenue requirements for the 2019 rate year.[43] They also include a study to help design the AMF proposal, equal to $2 million in the 2019 rate year.[44] If the Commission is to allow recovery of the costs of these projects in the revenue requirements for rate year 2019, then it will need to do so in this rate case.

Q. The Company has requested that the costs for the new grid modernization projects be recovered separately from base rates through a PST Factor. Does this obviate the need for the Commission to consider the proposed new grid modernization projects in this rate case docket?

A. No. As described in Mr. Woolf's testimony, the Division recommends that the Commission reject the Company's proposal to recover new grid modernization costs, or

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[42] Testimony of the Power Sector Transformation Panel, January 12, 2018, p. 27.
[43] Response to (Docket 4770) Division 32-23.
[44] Response to (Docket 4770) Division 19-8, Attachment DIV 19-8-3, pp 1-2.

any costs related to power sector transformation, in a PST Factor. Therefore, if the Commission is to allow recovery of the costs of these projects in the revenue requirements for rate year 2019, then it will need to do so in this rate case.

6.2. Integration of Distribution System Planning and Review

Q. Please explain why the Division does not support the Company's proposal to recover new grid modernization costs separately from base rates in a PST Factor.

A. As described in the Direct Testimony of Mr. Woolf, the Division strongly recommends that the Commission direct the Company to better integrate the planning, review, and cost recovery of the various projects that, in one way or another, contribute to providing reliable, safe, clean, and affordable distribution services. This includes more integrated planning practices for conventional distribution, grid modernization, DER-enabling, and DER projects. It also includes more integrated regulatory review of these projects, through rate cases, ISR cases, energy efficiency and system reliability plans, and any other practices established as a result of the PST initiative in Docket 4770 and 4780. National Grid has also stated a preference for better integration of the regulatory review of its distribution system and DER-related projects.[45]

The Division is opposed to a PST Factor because it moves in exactly the opposite direction by creating a new category of projects that will be given different regulatory treatment than other projects. First, it is difficult to distinguish between conventional distribution projects, grid modernization projects, DER-enabling projects, and DER projects. Second, this fractured approach makes it difficult for the Division and the

[45] Testimony of the Power Sector Transformation Panel, January 12, 2018, pages 16 and 29-30.

Commission to evaluate the distribution business activities of the Company on a logical, integrated basis. Third, ability to recover all PST costs on a reconciling basis, while recovering conventional distribution costs in the context of rate cases, would shift cost risks to ratepayers with little or no risk to the Company. This would provide the Company with inconsistent regulatory and financial incentives for projects that should be compared directly with each other on an equivalent basis.

6.3. Recommendations

Q. What do you recommend regarding National Grid's proposal for new grid modernization investments?

A. We recommend that the Commission reject National Grid's request for a PST Factor, and direct the Company to submit requests for recovery of any type of distribution costs through either the rate case process or the ISR process. As described in the direct testimony of Mr. Woolf, rejecting the proposed PST Factor is one of the Division's top priorities in Dockets 4770 and 4780.

We also support Mr. Booth's recommendation that the Commission direct the Company to submit a grid modernization plan that considers all potential distribution system projects and investments in an integrate fashion. The Commission should also direct the Company to eliminate the unwarranted distinction between conventional, grid modernization, DER-enabling, and DER projects, for the purpose of regulatory review and cost recovery.

7. ADVANCED METERING FUNCTIONALITY

7.1. National Grid's Proposal

Q. Please explain why the Company's proposed AMF investments are relevant to docket 4770.

A. As part of Docket 4780, the Company has requested approval to perform additional design work during FY 2019 in order to "provide the necessary groundwork for implementation of its future AMF investments" that it will submit for further review and approval by December 1, 2018.[46] The cost of this design work was very roughly estimated by the Company to be $2,000,000, and would impact the revenue requirements at issue in the instant docket.[47]

Q. Is AMF an investment that should be investigated further?

A. Yes. In order for Rhode Island to achieve the outcomes recommended by stakeholders in Docket 4600, AMF investments will be necessary. For example, AMF enables the following outcomes: "outage protection, faster outage restoration, access to various pricing options that can save [customers] money, access to energy efficiency and renewable services tailored to [customers'] usage, and more efficient use of the distribution system that creates consumer savings."[48]

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46 *Id,* page 37

47 Direct Testimony of the Power Sector Transformation Panel, January 12, 2018, page 4 and response to Attachment DIV 19-8-3 (Docket 4770).

48 Ibid., page 32.

Q. What analysis has the Company already performed with respect to AMF?

A. The Company has developed preliminary cost estimates associated with full deployment of advanced metering functionality in Rhode Island, and expects that the deployment will result in significant benefits to customers and system savings. These benefits include enhanced energy management capability, enablement of third party programs and offerings, enhanced volt-var optimization, avoided O&M costs, and storm outage management system improvements.[49]

The Company's initial benefit-cost analysis shows that the investment is expected to be cost-effective under six of eight scenarios. These scenarios are shown in the table below.

Rhode Island Only				
	Opt-In		**Opt-Out**	
	Low Savings	**High Savings**	**Low Savings**	**High Savings**
Net Benefits (NPV $Million)	-$55.23	$16.99	-$30.53	$68.90
Benefit-Cost Ratio	**0.79**	**1.07**	**0.88**	**1.27**
Rhode Island and New York Joint Implementation				
	Opt-In		**Opt-Out**	
	Low Savings	**High Savings**	**Low Savings**	**High Savings**
Net Benefits (NPV $Million)	$12.92	$85.14	$37.19	$137.05
Benefit-Cost Ratio	**1.07**	**1.44**	**1.19**	**1.72**

49 *Id*, page 38

7.2. The AMF Study

Q. Is it appropriate to conduct additional analysis prior to submitting an application for a full roll-out of AMF?

A. Yes. It is appropriate for several reasons. First, the potential benefits associated with AMF are large, but the costs are also large. Because of this, a relatively small percentage error in either direction on the estimated costs and benefits could have large consequences with respect to impacts on customers. To reduce this risk, it is appropriate to thoroughly study the costs and benefits prior to implementation.

Second, the technology and business models associated with AMF are evolving quickly. To fully capture the potential benefits associated with AMF, the Company should study new and emerging approaches to AMF – approaches that would reduce costs, avoid technology obsolescence, and reduce the risk of stranded costs. In other words, we believe that additional study could enable the Company to employ innovative practices for AMF implementation beyond what is typically done in the industry, potentially providing much greater net benefits to customers and serving as a model nationally.

Q. What innovative approaches to AMF should the Company study?

A. As discussed in the Rhode Island Power Sector Transformation report,[50] the Company should study the potential for shared communication infrastructure and enabling access to

[50] Rhode Island Power Sector Transformation report, November 8, 2017, page 42.

third party providers. In addition, we recommend that the Company investigate procurement of AMF as a service, rather than through a capital investment.

Q. Please describe the potential benefits of shared communication infrastructure.

A. The communication infrastructure backbone is one of the most costly aspects of AMF deployment. By sharing or expanding upon that infrastructure through partnerships, significant customer savings could be achieved.

Q. Please describe the benefits of enabling access to third party providers.

A. The competitive market is rapidly expanding the number of value-added services that can be provided to customers based on an individual customer's usage information. With appropriate privacy and security protections, enabling access to meter data and capabilities can greatly expand the services provided to customers in Rhode Island. For example, through analysis of customer data, customers could be offered energy efficiency, demand response, or distributed generation products tailored to their usage profiles.

In addition, new services are emerging that disaggregate customer usage data to provide services such as predictive analytics and preventative maintenance (e.g., informing customers that their furnace is working harder than normal, so it may be time to replace the filter), or informing customers about happenings in their home (for example, that their kids are home or that their attic light is on).[51]

[51] Examples of such companies currently providing these services are Powerley and Whisker Labs.

Q. Please explain what you mean by the procurement of "AMF as a service."

A. In many industries, equipment manufacturers now provide equipment-as-a-service, rather than requiring customers to purchase the equipment through a large capital investment. A similar concept is being applied to the smart grid through "smart-grid-as-a-service"[52] or "metering-as-a-service" where a third party provider owns the equipment, fully manages the project, and provides operational support to utilities through a subscription service.[53] This approach is already common for software, but is becoming more common for hardware as well. For example, Leidos has provided this service to several municipalities and cooperatives nationwide.[54] A presentation by the Company includes the following

[52] Tom Damon and Josh Wepman, "Smart Grid as a Service: An Alternative Approach to Tackling Smart Grid Challenges," *Electric Energy T&D*, May 2011, http://electricenergyonline.com/show_article.php?mag=71&article=575.

[53] MeterSys, "Metering as a Service® (MaaS)," MeterSys Advanced Metering Solutions, 2018, https://metersys.com/metering-as-a-services-maas/.

[54] See, for example: Smart Grid Today, "Lansing, Mich, Hires Leidos to Deploy Smart Grid," *Smart Grid Today*, July 20, 2017, https://www.smartgridtoday.com/public/Lansing-Mich-hires-Leidos-to-deploy-smart-grid.cfm.

comparison of utility AMI deployment strategies:[55]

Comparison with Types of AMI Deployments

Features	Traditional Own/Operate	Software as a Service (Hosted)	Fully Managed Service
Contract Prime	Utility	Utility	Leidos
Project Management	Utility	Utility	Leidos
Meter Warranty	1 year	1 year	Full Term
Business Case Workshop	Internal or paid for with consultant - Extra	Utility conducted	Included
Business Process Change	Limited execution - OJBPC	Utility conducted - OJBPC	Leidos Provided
Advanced Analytics	Limited – via contractor or consultant – Extra	Limited – via contractor or consultant – Extra	Included
Operational Support	Internal – or via calls with separate vendors - Extra	Internal – or via calls with separate vendors.	End-to-End Proactive Support
Field Systems	Utility troubleshooting	Utility troubleshooting	Utility Hands and Eyes
SLAs	N/A	N/A	End-to-End Business SLAs
Price	$$$$+	$$ + $$	$$$

Q. What has the Company proposed as part of its design work?

A. The Company states that the study will be used "to undertake the next phase of design, including further exploration of partnerships, stakeholder input, and other innovative program elements, and to undertake a procurement exercise."[56] In particular, the Company states that it has "commenced an effort to explore the value of a state-wide communications system," and has issued a Request for Information to identify qualified suppliers to receive an end-to-end "Request for Solution" and to gather market

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[55] Steven Root, "Best Practices on AMI Implementation and Operations for Improving Efficiency," November 5, 2015, http://www.publicpower.com/pdf/ecc15/Steven_Root.pdf.

[56] *Id.*, Page 3 of 31.

intelligence. In addition, the Company proposes to explore additional functionalities including load disaggregation and gas demand response.[57]

Q. Please describe the work associated with conducting this design work.

A. The Company has not provided a detailed description for the study. Instead, the Company developed a very general estimate of the costs at the departmental function level for its New York affiliate[58] that lacked detail. From this New York estimate, the Company extrapolated a study cost that would apply to a combined New York/Rhode Island study.

Q. What is your assessment of the Company's AMF study proposal?

A. The decision of whether and how to pursue AMF should not be taken lightly. It is a very large investment with potentially large benefits. For this reason, the Company should explore deployment scenarios, technologies, and other options very carefully. However, the Company has not provided sufficient detail to justify spending $2 million on such a study in Rhode Island, particularly when it states that such a study would be similar to that undertaken by its New York affiliate.[59] Division witness Michael Ballaban addresses the cost of the study in his testimony, including what should be allowed in the revenue requirement.

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[57] Response to (4770) Division 32-19.
[58] Response to (4770) Division 23-5
[59] Response to (4770) Division 23-5

7.3. Recommendations

Q. What do you recommend regarding the Company's AMF study?

A. The Company's analysis shows AMI to be very promising, and it is clear that further study is warranted to develop the best approach for implementing AFM. However, such a study should be designed to provide additional value beyond the exploration that the Company is undertaking in New York. For this reason, we recommend that the Commission direct the Company to work with the Division to develop a study plan that provides significant additional information to the New York study. Further, the Company should be required to periodically meet with the Division to discuss the study findings and file a report with the Commission at the conclusion of the process. Following submittal of the AMI study, the Division recommends that the Commission open a docket to examine the study with stakeholders and to design a phased approach to application of time varying rates consistent with the principles of Docket 4600.

8. BENEFIT-COST ANALYSES

8.1. The Role of Benefit-Cost Analyses

Q. Please explain why benefit-cost analyses relevant in this rate case.

A. As described in Section 3, the Commission should address PIMs in this rate case docket because of the important inter-relationship between PIMs and the authorized ROE. Benefit-cost analyses are a critical element in designing PIMs, because they can help shed light on the potential net benefits of PIM activities, and thereby inform decisions regarding the magnitude of PIM incentives. Ideally, PIM incentives should be set at a level that will result in net benefits to customers.

Q. Please provide an overview of the role of benefit-cost analysis (BCA) in Rhode Island.

A. The role of cost-effectiveness (and thus BCAs) was recently addressed in Docket 4600. In April 2017, the Docket 4600 stakeholder working group submitted a report to the Commission providing recommendations for a new cost-effectiveness test, among other things.[60] The proposed Rhode Island Benefit-Cost Framework built off the cost-effectiveness test that has been used historically for energy efficiency resources, and included a broader range of costs and benefits to better reflect power sector transformation and state energy policy goals.

In October 2017, the Commission issued a Guidance Document that provided direction on how to address the issues raised in Docket 4600, and accepted the proposed RI Benefit-Cost Framework as the appropriate cost-effectiveness methodology.[61]

Q. What does the Commission's Guidance Document say about the role of BCAs?

A. The Guidance Document is clear that the RI Benefit-Cost Framework should play a central role in evaluating a wide range of utility proposals. Specifically, the Guidance Document states that:

> in any case that proposes new programs or capital investment that will affect National Grid's electric distribution rates, the impact of any increased ratepayer recovery should also reference the goals, rate design principles, and Benefit-Cost Framework. National Grid should apply the Benefit-Cost Framework to changes

[60] Docket 4600 Stakeholder Working Group, Report to the Rhode Island Public Utilities Commission, April 5, 2017.

[61] Rhode Island Public Utilities Commission, Docket 4600, *Guidance on Goals, Principles, and Values for Matters Involving the Narragansett Electric Company*, October 27, 2017.

> in its cost of service for the primary purpose of complying with State policy or to expand a current program.[62]

Q. What does the Commission's Guidance Document say about using quantitative and qualitative data in the RI Benefit-Cost Framework?

A. The Guidance Document acknowledges that there is still significant work remaining to identify and quantify some of the impacts in the new framework. It clarifies that:

> Where the costs and benefits can be quantified, the proponent should provide such information and the basis for the conclusion reached. Where quantification is not possible or not practical, the proponent should so explain. Regardless of whether the quantification can be fully completed, a qualitative analysis should be included.[63]

Q. Is the Benefit-Cost Framework the only factor that should be used to evaluate proposals for new investments and new projects?

A. No. The Guidance Document states that:

> the Benefit-Cost Framework will not be the exclusive measure of whether a specific proposal should be approved. For example, there may be outside factors that need to be considered by the PUC regardless of whether a specific proposal is determined to be cost-effective or not. This may include statutory mandates or other qualitative considerations.[64]

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[62] Guidance Document, p. 6.
[63] Guidance Document, p. 6.
[64] Guidance Document, p. 7.

8.2. National Grid's Benefit-Cost Analyses

Q. Please provide an overview of the Company's BCA methodology.

A. National Grid applied two different approaches to evaluating costs and benefits. For the grid-side investments that are made to enable DER (i.e., those described in Chapter 3 of their PST filing), the Company used a best-fit/least-cost assessment methodology. For the investments in DER (i.e., those described in Chapters 4 through 7 of their PST filing) the Company applied a Rhode Island specific cost-effectiveness methodology.

Q. Please describe the best-fit/least-cost methodology used by the Company for DER-enabling[65] investments.

A. The Company refers to a recent US Department of Energy "Decision Guide" (DOE Report) as the source of that methodology. That report presents many different considerations for the best way to implement advanced distribution system technologies, including DERs.[66] With regard to cost-effectiveness considerations, the DOE Report describes advanced distribution system technologies as belonging to four categories: (a) traditional utility infrastructure investments; (b) DER-enabling investments; (c) DER-integration investments; and (d) self-support or direct-charge investments (i.e., those paid for by customers or third-parties). The DOE Report recommends that traditional and DER-enabling investments be subject to a best-fit/least-cost analysis or a traditional

[65] We prefer not using the categories and terms "DER-enabling" and DER-integration," because the categories are not well-defined and the distinctions are difficult to make. We use these terms in this testimony in order to be consistent with the Company's terminology.

[66] The US Department of Energy, Modern Distribution Guide, Volume III, June 2017, Section 3.4.1.

utility benefit-cost analysis, and that DER-integration investments be subject to a societal benefit-cost analysis.[67]

In this Docket, the Company notes that it used the best-fit/least cost method "to evaluate proposed grid-side investments to enable DER using a conceptual cost estimate and an expectation that it will utilize a competitive procurement process as part of the deployment."[68]

Q. Do you agree with the Company's use of the best-fit/least-cost methodology for DER-enabling investments?

A. No. First, the Division is concerned about the way that the Company evaluated and proposed the DER-enabling investments in the absence of a more comprehensive, long-term grid modernization plan. This concern is addressed in more detail by Mr. Booth.

Second, the best-fit/least-cost approach used by the Company does not include any quantitative assessment of the potential benefits of the proposed investments. National Grid does not provide any benefit-cost analysis for these investments; it only provides a narrative description of what the investments will do and why they are needed.

We note that the DOE Report is clear that it may be appropriate to apply benefit-cost analyses to DER-enabling projects. It states that utilities could use best-fit/least-cost methodologies <u>or</u> traditional utility cost-benefit analyses.[69] National Grid has chosen not to use a traditional utility BCA. Further, there is nothing in the DOE Report to suggest that the Company cannot or should not use a different type of BCA, such as the RI

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[67] The US Department of Energy, Modern Distribution Guide, Volume III, June 2017, Section 3.4.1.
[68] PST Panel Direct Testimony, p. 25, lines 14-17.
[69] DOE Report, p. 39 and p. 40.

Benefit-Cost Framework, if so directed by the Commission. National Grid has chosen not to.

Q. Do you think that National Grid should use some form of BCA to justify its proposed DER- enabling investments in this docket?

A. Yes. The DER-enabling projects that the Company proposes in this docket include a total of $17.3 million over the three-year period from FY2018 – FY2020.[70] This is significantly larger than any other PST initiative in this docket (with the exception of the AMF proposal that the Company is not asking for approval of in this docket) and thus warrants more justification than the narrative that National Grid has provided.

Q. Does the fact that the Company is asking for a form of pre-approval of its PST investments affect the importance of using a BCA to justify its proposed grid-enabling investments?

A. Yes. The Company is essentially asking the Commission for pre-approval of its PST investments.[71] As a general matter, any request for pre-approval of a project should be supported with a comprehensive justification for the project, including a demonstration that the project is cost-effective and will result in net benefits to customers. In the absence of such a justification, the Commission should not pre-approve a project. The Company has not provided such a justification for the DER-enabling projects in this docket.

[70] Response to (4770) Division 19-8-3

[71] PST Panel Direct Testimony, p. 96, lines 1-4. Schedule PST- 1, Chapter 10, page 1.

It is important to note that this does not mean that the Company should not undertake those DER-enabling projects. It means only that the Commission should not pre-approve them without sufficient justification. If the Company believes that the DER-enabling projects will result in net benefits to customers, then it should undertake those investments and seek recovery of them in the next rate case.

Q. Are there other reasons why the Company should apply a BCA to the DER-enabling investments?

A. Yes. The Company's proposal to categorize DER-enabling projects differently from traditional distribution system projects and from DER-integrating investments creates several problems. It is often difficult to draw a clear distinction between conventional and DER-related projects, as described in more detail in Mr. Booth's direct testimony. It is also difficult to draw a clear distinction between DER-enabling and DER-integrating technologies. Creating different standards of analysis and review for different categories that are hard to define can lead to some projects being improperly categorized and thus improperly treated.

In addition, the Company's proposal means that traditional projects, DER-enabling projects, DER-integration projects are subject to different standards of review. Traditional projects would be subject to the standard of review applied in the existing rate case and ISR processes, while DER-enabling projects are subject to a best-fit/least cost standard, and DER-integration projects are subject to a standard based on the RI Benefit-Cost Framework. This could result in some projects being inappropriately accepted or rejected simply because they are subject to inconsistent standards. This would clearly be inconsistent with the Commission's directives in Docket 4600 and state energy policy goals in general.

As described in the direct testimony of Mr. Woolf, National Grid should be seeking ways to better integrate the planning of all types of resources, including EE, SRP, ISR, DER-enabling, and DER-integrating resources. The Company's proposal to treat DER-enabling and DER-integrating resources different goes directly against this key goal.

Q. Please describe the cost-effectiveness methodology used by the Company for DER-integrating investments.

A. The Company's cost-effectiveness methodology was designed to reflect the RI Benefit-Cost Framework approved by the Commission in its Guidance Document. Some of the costs and benefits are not yet sufficiently developed to be used in a quantitative fashion, so the Company simply addressed them qualitatively. The Company also vetted some of the inputs and value drivers with comparable exercises that it has undertaking for its Massachusetts and New York affiliates. The Company used assumptions and methodologies that are used to evaluate the EE programs, including all applicable avoided costs from the 2015 New England Avoided Energy Supply Costs report.[72]

[72] PST Panel Direct Testimony, pp.25-26.

8.3. Critique of National Grid’s Benefit-Cost Analysis

Q. Do you agree with the overall approach National Grid used for its BCAs?

A. For those projects where it applied a BCA, the Company used the RI Benefit-Cost Framework approved by the Commission in the 4600 Guidance Document. This is clearly the appropriate framework to use in this context. In addition, the Company appropriately included a discussion of the qualitative benefits for each project, as required in the 4600 Guidance Document.

However, we have concerns with three of the inputs that the Company used in its BCAs. First, National Grid does not include any benefits associated with avoided distribution costs in its BCAs. Second, it appears as though the Company used outdated avoided FCM capacity costs in its BCA. Third, the Company used a discount rate based on its weighted average cost of capital, rather than a societal discount rate that would be more appropriate with the RI Benefit-Cost Framework.

Q. Please elaborate on your concern that National Grid does not include any benefits associated with avoided distribution costs.

A. In all of its BCAs, National Grid assumes that there will be no avoided distribution system costs. This is presumably because the Company did not have estimates of avoided distribution costs that it deemed sufficiently robust. In addition, avoided distribution costs can vary significantly by geographic location, creating another challenge in identifying reasonable assumptions for a BCA.

We are sympathetic to the limitations of current estimates of avoided distribution costs. However, assuming that DERs will provide no value in the form of avoided distribution costs is overly conservative. Distribution system benefits can be significant, particularly for some types of DERs, such as demand response or storage, which could be specifically designed to defer or avoid distribution projects. This assumption by National Grid will result in understating the benefits of the projects analyzed in the BCAs.

Q. Please elaborate on your concern that National Grid may have used outdated avoided FCM costs.

A. It is not clear what source National Grid used to determine avoided FCM capacity costs. In some instances, the Company refers to the 2015 AESC Report as the source of avoided cost assumptions for its BCAs.[73] In other instances, the Company refers to the AESC 2015 Update,[74] which was performed to reflect significant changes that had occurred in the New England wholesale electricity markets after the original report was conducted.[75] The distinction is very important because the avoided costs in the AESC 2015 Update are significantly lower than in the 2015 AESC Report.

Our review of the Company's assumptions suggests that the values used were those from the 2015 AESC Report. The Company's avoided FCM assumptions[76] are considerably higher than those included in the AESC 2015 Update.[77] If it is true that National Grid used the original 2015 AESC values, then its BCAs will overstate the benefits of the projects analyzed in the BCAs.

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[73] Schedule PST – 1, Chapter 2, p. 5, footnote 5.

[74] Docket 4770 Response to Division 25-6, Attachment DIV 25-6, p. 1.

[75] Tabors, Caramanis, Rudkevich, *AESC 2015 Update Results and Assumptions*, memo to the AESC Update Client Group, December 2016.

[76] Response to (4770) Division 25-6, Attachment DIV 25-6, p. 1.

[77] As reported in the AESC 2015 Update, Appendix B, p 1 of 2.

Q. Why do you believe that a societal discount rate should be used when applying the RI Benefit-Cost Framework?

A. A societal discount rate is most consistent with the RI Cost-Benefit Framework. The Framework includes several impacts that are societal in nature, such as environmental, job and economic development, low-income, and public health impacts. The RI framework essentially represents a societal perspective, which warrants using a discount rate that also reflects a societal perspective.

In addition, the Commission's Guidance Document in 4600 emphasizes the importance of long-term objectives and policy goals. The Guidance Document begins with a list of stated electric industry goals that were approved by the Commission. The first goal is to provide "reliable, safe, clean, and affordable energy to Rhode Island customers over the *long term*" (emphasis added).[78] The next two goals refer to addressing climate change and other environmental challenges, and promoting jobs and economic development; which also suggest a preference for long-term objectives and policy goals. As noted below, a societal discount rate places greater emphasis on long-term impacts, relative to a discount rate based on a utility WACC.

Further, using a utility WACC for a discount rate is not consistent with the goals of the Company's benefit-cost analysis in general.[79] A utility WACC represents the time preference of utility investors, primarily based on the cost of capital and the risks to those investors. A utility WACC would be appropriate for the purposes of maximizing value to

[78] Rhode Island Public Utilities Commission, Docket 4600 Guidance Document, page 3.

[79] For additional discussion of this point, see: National Efficiency Screening Project, *the National Standard Practice Manual*, Chapter 9, May 2017.

utility investors, but this is not the purpose of the BCA. The purpose of the BCA is to identify the optimal mix of resources that will lead to "reliable, safe, clean, and affordable energy to Rhode Island customers over the long-term."[80] A societal discount rate is much more consistent with this purpose.

Finally, a societal discount rate is consistent with the discount rate that has been used for EE cost-effectiveness analysis for many years. In that context, National Grid uses a low-risk discount rate based on US Government Treasury Bills. This rate tends to be much lower than the utility WACC, and is sometimes used to represent a societal discount rate.

Q. How does a societal discount rate compare with a utility's WACC?

A. A societal discount rate is typically much lower than a utility's WACC. There is a range of views on what a societal discount rate should be, and the specific value of a societal discount rate should depend upon the impacts and the analysis it is applied to. Some analysts argue that a societal discount rate for valuing environmental impacts should be negative (in real terms). Others use societal discount rates on the order of one, two, or three percent (in real terms).[81] This entire range of societal discount rates is lower than the Company's WACC which is 7.5 percent in nominal terms, and 4.8 percent in real terms.

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[80] Rhode Island Public Utilities Commission, Docket 4600 Guidance Document, page 3.
[81] National Standard Practice Manual, page 75.

Q. In general, how does using a societal discount rate affect the results of the cost-effectiveness analyses?

A. A lower discount rate will give greater weight to long-term costs and benefits than to short-term impacts as compared to a higher discount rate. In most cases, the PST initiatives require capital costs to be incurred in the early years while the benefits are experienced over a longer period of time. Consequently, a lower discount rate will typically indicate increased benefits, increased net benefits, and a higher benefit-cost ratio as compared to a higher discount rate like the WACC.

Q. Please provide an example of how the lower societal discount rate will affect the BCA results.

A. As one example, we used different discount rates for the Company's BCA for advanced metering infrastructure, in the case where the AMF costs are shared with New York, and in the Opt-Out Low Participation Scenario. Using the discount rate equal to the Company's WACC (4.8 percent in real terms) results in a benefit-cost ratio is 1.19; using a societal discount rate of two percent (in real terms), results in a benefit-cost ratio of 1.34; and using the current energy efficiency BCA discount rate of roughly 0.3 percent (in real terms) results in a benefit-cost ratio of 1.44.

8.4. Recommendations

Q. What do you recommend regarding the Company's use of the best-fit/least cost methodology to assess DER-enabling projects?

A. We recommend that the Commission reject the Company's proposal to evaluate any PST related projects, or any projects for which it is seeking pre-approval, with the best-fit/least cost methodology. This methodology is inconsistent with the Docket 4600 Guidance Document; is inconsistent with the overall goal of integrating the planning, review, and approval of all types of distribution system investment; and does not provide sufficient justification for the Commission to pre-approve projects.

Q. Which discount rate do you recommend be used for benefit-cost analyses in this docket?

A. We recommend that the Commission determine that a societal discount rate is the most appropriate rate to use when applying the Rhode Island Benefit-Cost Framework, and that the Commission direct the Company and other analysts to use a societal discount rate for all future applications of that framework. For the purposes of this rate case docket, we recommend that the Commission recognize that the Company's BCA results likely understate project benefits because the Company's discount rate is too high.

Q. What do you recommend regarding the benefits that the Company did not include in its benefit-cost analyses?

A. We recommend that the Commission recognize that the Company's BCA results likely understate project benefits because they do not include the benefits of avoiding distribution system costs. Further, the extent of any understatement will likely vary by PST initiative, such that one may not be able to directly compare the BCAs across initiatives.

Q. What do you recommend regarding the outdated avoided costs that the Company appears to be using?

A. We recommend that the Commission recognize that the Company's BCA results likely overstate project benefits, particularly avoided FCM capacity costs, because they appear to use outdated avoided cost assumptions that are higher than more recent assumptions.

Q. You have identified several significant problems with the Company's BCAs, two of which understate benefits, and one of which overstates benefits. Are you concerned that these problems will lead to the Commission approving uneconomic outcomes in this docket?

A. According to National Grid's proposal, all the PST initiatives that National Grid is proposing in this docket will be subject to further review by the Commission prior to them being undertaken by the Company. These PST initiatives will be included in the annual PST Plans that will be filed with the Commission. The first Plan will be filed by December 1, 2018, to investigate the potential PST initiatives for FY 2020.[82] At that time, the Company should file updated BCAs for each PST initiative that it seeks approval for, with improved methodologies and inputs using the Commission directives from this docket.

The Division has a different proposal for the review and approval of PST initiatives, as described in the direct testimony of Mr. Woolf. The Division recommends that, in the absence of a multi-year rate plan over the next three years, the Company

[82] PST Panel Direct Testimony, p. 5, lines 4-7.

should plan for and undertake PST initiatives that it expects to be cost-effective and to provide net benefits to customers without specific pre-approval from the Commission.

Consequently, under either the Division's or the Company's PST review proposal, the BCA results presented in this docket will not be the final BCA results used to make decisions on future PST initiatives.

Q. Does this conclude your direct testimony?

A. Yes, it does.

AFFIDAVIT OF TIM WOOLF

Tim Woolf, does hereby depose and say as follows:

I, Tim Woolf, on behalf of the Rhode Island Division of Public Utilities and Carriers, certify that testimony that bears my name was prepared by me or under my supervision and is true and accurate to the best of my knowledge and belief.

Signed under the penalties of perjury this the 6th day of April, 2018.

Tim Woolf
Tim Woolf (Apr 5, 2018)

Tim Woolf

AFFIDAVIT OF MELISSA WHITED

Melissa Whited, does hereby depose and say as follows:

I, Melissa Whited, on behalf of the Rhode Island Division of Public Utilities and Carriers, certify that testimony that bears my name was prepared by me or under my supervision and is true and accurate to the best of my knowledge and belief.

Signed under the penalties of perjury this the 6th day of April, 2018.

M. Whited
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Melissa Whited

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PROFESSIONAL EXPERIENCE

Synapse Energy Economics Inc., Cambridge, MA. *Vice President*, 2011 – present.

Provides expert consulting on the economic, regulatory, consumer, environmental, and public policy implications of the electricity and gas industries. The primary focus of work includes technical and economic analyses, electric power system planning, climate change strategies, energy efficiency programs and policies, renewable resources and related policies, power plant performance and economics, air quality, and many related aspects of consumer and environmental protection.

Massachusetts Department of Public Utilities, Boston, MA. *Commissioner*, 2007 – 2011.

Oversaw a significant expansion of clean energy policies as a consequence of the Massachusetts Green Communities Act, including an aggressive expansion of ratepayer-funded energy efficiency programs; the implementation of decoupled rates for electric and gas companies; an update of the DPU energy efficiency guidelines; the promulgation of net metering regulations; review of smart grid pilot programs; and review of long-term contracts for renewable power. Oversaw six rate case proceedings for Massachusetts electric and gas companies. Played an influential role in the development of price responsive demand proposals for the New England wholesale energy market. Served as President of the New England Conference of Public Utility Commissioners from 2009-2010. Served as board member on the Energy Facilities Siting Board from 2007-2010. Served as co-chair of the Steering Committee for the Northeast Energy Efficiency Partnership's Regional Evaluation, Measurement and Verification Forum.

Synapse Energy Economics Inc., Cambridge, MA. *Vice President*, 1997 – 2007.

Tellus Institute, Boston, MA. *Senior Scientist, Manager of Electricity Program*, 1992 – 1997.

Association for the Conservation of Energy, London, England. *Research Director*, 1991 – 1992.

Massachusetts Department of Public Utilities, Boston, MA. *Staff Economist*, 1989 – 1990.

Massachusetts Office of Energy Resources, Boston, MA. *Policy Analyst*, 1987 – 1989.

Energy Systems Research Group, Boston, MA. *Research Associate*, 1983 – 1987.

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EDUCATION

Boston University, Boston, MA
Master of Business Administration, 1993

London School of Economics, London, England
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Tufts University, Medford, MA
Bachelor of Science in Mechanical Engineering, 1982

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Bachelor of Arts in English, 1982

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TESTIMONY

Rhode Island Public Utilities Commission (Docket No. 4783): Direct testimony of Tim Woolf and Melissa Whited regarding National Grid's Advanced Metering Functionality Pilot. On behalf of the Rhode Island Division of Public Utilities and Carriers. February 22, 2018.

New York Public Service Commission (Case 17-E-0459): Direct testimony of Tim Woolf regarding Energy Efficiency Earnings Adjustment Mechanisms proposed by Central Hudson Gas & Electric Company. On behalf of Natural Resources Defense Council. November 21, 2017.

New York Public Service Commission (Case 17-E-0238): Direct and rebuttal testimony of Tim Woolf and Melissa Whited regarding Earnings Adjustment Mechanisms proposed by National Grid. On behalf of Advanced Energy Economy Institute. August 25 and September 15, 2017.

Utah Public Service Commission (Docket No. 14-035-114): Direct and rebuttal testimony of Tim Woolf regarding the Pacificorp's analysis of the benefits and costs associated with distributed generation resources. On behalf of Utah Clean Energy. June 8, 2017 and July 25, 2017.

Massachusetts Department of Public Utilities (D.P.U. 17-05): Direct and surrebuttal testimony of Tim Woolf and Melissa Whited regarding performance-based regulation, the monthly minimum reliability contribution, storage pilots, and rate design in Eversource's petition for approval of rate increases and a performance-based ratemaking mechanism. On behalf of Sunrun and the Energy Freedom Coalition of America, LLC. April 28, 2017 and May 26, 2017.

Massachusetts Department of Public Utilities (D.P.U. 15-120, D.P.U. 15-121, D.P.U. 15-122/15-123): Direct testimony of Tim Woolf and Ariel Horowitz, PhD, regarding the petitions by National Grid, Unitil, NSTAR, and Eversource Energy for approval of their grid modernization plans. On behalf of Conservation Law Foundation. March 10, 2017.

Massachusetts Department of Public (D.P.U. 16-169): Direct testimony of Tim Woolf and Erin Malone regarding Nation Grid's petition for ruling regarding the provision of gas energy efficiency services. On behalf of the Cape Light Compact. November 2, 2016.

New Jersey Board of Public Utilities (Docket No. ER16060524): Direct testimony regarding Rockland Electric Company's proposed advanced metering program. On behalf of the New Jersey Division of Rate Counsel. September 9, 2016.

Colorado Public Utilities Commission (Proceeding No. 16AL-0048E): Answer testimony regarding Public Service Company of Colorado's rate design proposal. On behalf of Energy Outreach Colorado. June 6, 2016.

Georgia Public Service Commission (Docket No. 40161 and Docket No. 40162): Direct testimony regarding the demand-side management programs proposed by Georgia Power Company in its Certification, Decertification, and Amended Demand-Side Management Plan and its 2016 Integrated Resource Plan. On behalf of Sierra Club. May 3, 2016.

Massachusetts Department of Public Utilities (Docket No. 15-155): Joint direct and rebuttal testimony with M. Whited regarding National Grid's rate design proposal. On behalf of Energy Freedom Coalition of America, LLC. March 18, 2016 and April 28, 2016.

Maine Public Utilities Commission (Docket No. 2015-00175): Direct testimony on Efficiency Maine Trust's petition for approval of the Triennial Plan for Fiscal Years 2017-2019. On behalf of the Natural Resources Council of Maine and the Conservation Law Foundation. February 17, 2016.

Nevada Public Utilities Commission (Docket Nos. 15-07041 and 15-07042): Direct testimony on NV Energy's application for approval of a cost of service study and net metering tariffs. On behalf of The Alliance for Solar Choice. October 27, 2015.

New Jersey Board of Public Utilities (Docket No. ER14030250): Direct testimony on Rockland Electric Company's petition for investments in advanced metering infrastructure. On behalf of the New Jersey Division of Rate Counsel. September 4, 2015.

Utah Public Service Commission (Docket No. 14-035-114): Direct, rebuttal, and surrebuttal testimony on the benefit-cost framework for net energy metering. On behalf of Utah Clean Energy, the Alliance for Solar Choice, and Sierra Club. July 30, 2015, September 9, 2015, and September 29, 2015.

Nova Scotia Utility and Review Board (Matter No. M06733): Direct testimony on EfficiencyOne's 2016-2018 demand-side management plan. On behalf of the Nova Scotia Utility and Review Board. June 2, 2015.

Missouri Public Service Commission (Case No. ER-2014-0370): Direct and surrebuttal testimony on the topic of Kansas City Power and Light's rate design proposal. On behalf of Sierra Club. April 16, 2015 and June 5, 2015.

Missouri Public Service Commission (File No. EO-2015-0055): Rebuttal and surrebuttal testimony on the topic of Ameren Missouri's 2016-2018 Energy Efficiency Plan. On behalf of Sierra Club. March 20, 2015 and April 27, 2015.

Florida Public Service Commission (Dockets No. 130199-EI et al.): Direct testimony on the topic of setting goals for increasing the efficiency of energy consumption and increasing the development of demand-side renewable energy systems. On behalf of the Sierra Club. May 19, 2014.

Massachusetts Department of Public Utilities (Docket No. DPU 14-86): Direct and rebuttal Testimony regarding the cost of compliance with the Global Warming Solution Act. On behalf of the Massachusetts Department of Energy Resources and the Department of Environmental Protection. May 16, 2014.

Kentucky Public Service Commission (Case No. 2014-00003): Direct testimony regarding Louisville Gas and Electric Company and Kentucky Utilities Company's proposed 2015-2018 demand-side management and energy efficiency program plan. On behalf of Wallace McMullen and the Sierra Club. April 14, 2014.

Maine Public Utilities Commission (Docket No. 2013-168): Direct and surrebuttal testimony regarding policy issues raised by Central Maine Power's 2014 Alternative Rate Plan, including recovery of capital costs, a Revenue Index Mechanism proposal, and decoupling. On behalf of the Maine Public Advocate Office. December 12, 2013 and March 21, 2014.

Colorado Public Utilities Commission (Docket No. 13A-0686EG): Answer and surrebuttal testimony regarding Public Service Company of Colorado's proposed energy savings goals. On behalf of the Sierra Club. October 16, 2013 and January 21, 2014.

Kentucky Public Service Commission (Case No. 2012-00578): Direct testimony regarding Kentucky Power Company's economic analysis of the Mitchell Generating Station purchase. On behalf of the Sierra Club. April 1, 2013.

Nova Scotia Utility and Review Board (Matter No. M04819): Direct testimony regarding Efficiency Nova Scotia Corporation's Electricity Demand Side Management Plan for 2013 – 2015. On behalf of the Counsel to Nova Scotia Utility and Review Board. May 22, 2012.

Missouri Office of Public Counsel (Docket No. EO-2011-0271): Rebuttal testimony regarding IRP rule compliance. On behalf of the Missouri Office of the Public Counsel. October 28, 2011.

Nova Scotia Utility and Review Board (Matter No. M03669): Direct testimony regarding Efficiency Nova Scotia Corporation's Electricity Demand Side Management Plan for 2012. On behalf of the Counsel to Nova Scotia Utility and Review Board. April 8, 2011.

Rhode Island Public Utilities Commission (Docket No. 3790): Direct testimony regarding National Grid's Gas Energy Efficiency Programs. On behalf of the Division of Public Utilities and Carriers. April 2, 2007.

North Carolina Utilities Commission (Docket E-100, Sub 110): Filed comments with Anna Sommer regarding the Potential for Energy Efficiency Resources to Meet the Demand for Electricity in North Carolina. Synapse Energy Economics on behalf of the Southern Alliance for Clean Energy. February 2007.

Rhode Island Public Utilities Commission (Docket No. 3765): Direct and Surrebuttal testimony regarding National Grid's Renewable Energy Standard Procurement Plan. On behalf of the Division of Public Utilities and Carriers. January 17, 2007 and February 20, 2007.

Minnesota Public Utilities Commission (Docket Nos. CN-05-619 and TR-05-1275): Direct testimony regarding the potential for energy efficiency as an alternative to the proposed Big Stone II coal project. On behalf of the Minnesota Center for Environmental Advocacy, Fresh Energy, Izaak Walton League of America, Wind on the Wires and the Union of Concerned Scientists. November 29, 2006.

Rhode Island Public Utilities Commission (Docket No. 3779): Oral testimony regarding the settlement of Narragansett Electric Company's 2007 Demand-Side Management Programs. On behalf of the Division of Public Utilities and Carriers. November 24, 2006.

Nevada Public Utilities Commission (Docket Nos. 06-04002 & 06-04005): Direct testimony regarding Nevada Power Company's and Sierra Pacific Power Company's Renewable Portfolio Standard Annual Report. On behalf of the Nevada Bureau of Consumer Protection. October 26, 2006

Nevada Public Utilities Commission (Docket No. 06-06051): Direct testimony regarding Nevada Power Company's Demand-Side Management Plan in the 2006 Integrated Resource Plan. On behalf of the Nevada Bureau of Consumer Protection. September 13, 2006.

Nevada Public Utilities Commission (Docket Nos. 06-03038 & 06-04018): Direct testimony regarding the Nevada Power Company's and Sierra Pacific Power Company's Demand-Side Management Plans. On behalf of the Nevada Bureau of Consumer Protection. June 20, 2006.

Nevada Public Utilities Commission (Docket No. 05-10021): Direct testimony regarding the Sierra Pacific Power Company's Gas Demand-Side Management Plan. On behalf of the Nevada Bureau of Consumer Protection. February 22, 2006.

South Dakota Public Utilities Commission (Docket No. EL04-016): Direct testimony regarding the avoided costs of the Java Wind Project. On behalf of the South Dakota Public Utilities Commission Staff. February 18, 2005.

Rhode Island Public Utilities Commission (Docket No. 3635): Oral testimony regarding the settlement of Narragansett Electric Company's 2005 Demand-Side Management Programs. On behalf of the Division of Public Utilities and Carriers. November 29, 2004.

British Columbia Utilities Commission. Direct testimony regarding the Power Smart programs contained in BC Hydro's Revenue Requirement Application 2004/05 and 2005/06. On behalf of the Sierra Club of Canada, BC Chapter. April 20, 2004.

Maryland Public Utilities Commission (Case No. 8973): Oral testimony regarding proposals for the PJM Generation Attributes Tracking System. On behalf of the Maryland Office of People's Counsel. December 3, 2003.

Rhode Island Public Utilities Commission (Docket No. 3463): Oral testimony regarding the settlement of Narragansett Electric Company's 2004 Demand-Side Management Programs. On behalf of the Division of Public Utilities and Carriers. November 21, 2003.

California Public Utilities Commission (Rulemaking 01-10-024): Direct testimony regarding the market price benchmark for the California renewable portfolio standard. On behalf of the Union of Concerned Scientists. April 1, 2003.

Québec Régie de l'énergie (Docket R-3473-01): Direct testimony with Philp Raphals regarding Hydro-Québec's Energy Efficiency Plan: 2003-2006. On behalf of Regroupment national des Conseils régionaux de l'environnement du Québec. February 5, 2003.

Connecticut Department of Public Utility Control (Docket No. 01-10-10): Direct testimony regarding the United Illuminating Company's service quality performance standards in their performance-based ratemaking mechanism. On behalf of the Connecticut Office of Consumer Counsel. April 2, 2002.

Nevada Public Utilities Commission (Docket No. 01-7016): Direct testimony regarding the Nevada Power Company's Demand-Side Management Plan. On behalf of the Bureau of Consumer Protection, Office of the Attorney General. September 26, 2001.

United States Department of Energy (Docket Number-EE-RM-500): Comments with Bruce Biewald, Daniel Allen, David White, and Lucy Johnston of Synapse Energy Economics regarding the Department of Energy's proposed rules for efficiency standards for central air conditioners and heat pumps. On behalf of the Appliance Standards Awareness Project. December 2000.

US Department of Energy (Docket EE-RM-500): Oral testimony at a public hearing on marginal price assumptions for assessing new appliance efficiency standards. On behalf of the Appliance Standards Awareness Project. November 2000.

Connecticut Department of Public Utility Control (Docket No. 99-09-03 Phase II): Direct testimony regarding Connecticut Natural Gas Company's proposed performance-based ratemaking mechanism. On behalf of the Connecticut Office of Consumer Counsel. September 25, 2000.

Mississippi Public Service Commission (Docket No. 96-UA-389): Oral testimony regarding generation pricing and performance-based ratemaking. On behalf of the Mississippi Attorney General. February 16, 2000.

Delaware Public Service Commission (Docket No. 99-328): Direct testimony regarding maintaining electric system reliability. On behalf of Delaware Public Service Commission Staff. February 2, 2000.

Delaware Public Service Commission (Docket No. 99-328): Filed expert report ("Investigation into the July 1999 Outages and General Service Reliability of Delmarva Power & Light Company," jointly authored with J. Duncan Glover and Alexander Kusko). Synapse Energy Economics and Exponent Failure Analysis Associates on behalf the Delaware Public Service Commission Staff. February 1, 2000.

New Hampshire Public Service Commission (Docket No. 99-099 Phase II): Oral testimony regarding standard offer services. On behalf of the Campaign for Ratepayers Rights. January 14, 2000.

West Virginia Public Service Commission (Case No. 98-0452-E-GI): Rebuttal testimony regarding codes of conduct. On behalf of the West Virginia Consumer Advocate Division. July 15, 1999.

West Virginia Public Service Commission (Case No. 98-0452-E-GI): Direct testimony regarding codes of conduct and other measures to protect consumers in a restructured electricity industry. On behalf of the West Virginia Consumer Advocate Division. June 15, 1999.

Public Service Commission of West Virginia (Case No. 98-0452-E-GI): Filed expert report ("Measures to Ensure Fair Competition and Protect Consumers in a Restructured Electricity Industry in West Virginia," jointly authored with Jean Ann Ramey and Theo MacGregor) in the matter of the General Investigation to determine whether West Virginia should adopt a plan for open access to the electric power supply market and for the development of a deregulation plan. Synapse Energy Economics and MacGregor Energy Consultancy on behalf of the West Virginia Consumer Advocate Division. June 1999.

Massachusetts Department of Telecommunications and Energy (DPU/DTE 97-111): Direct testimony regarding Commonwealth Electric Company's energy efficiency plan, and the role of municipal aggregators in delivering demand-side management programs. On behalf of Cape and Islands Self-Reliance Corporation. January 1998.

Delaware Public Service Commission (DPSC 97-58): Direct testimony regarding Delmarva Power and Light's request to merge with Atlantic City Electric. On behalf of Delaware Public Service Commission Staff. May 1997.

Delaware Public Service Commission (DPSC 95-172): Oral testimony regarding Delmarva's integrated resource plan and DSM programs. On behalf of the Delaware Public Service Commission Staff. May 1996.

Colorado Public Utilities Commission (5A-531EG): Direct testimony regarding the impact of proposed merger on DSM, renewable resources and low-income DSM. On behalf of the Colorado Office of Energy Conservation. April 1996.

Colorado Public Utilities Commission (3I-199EG): Direct testimony regarding the impacts of increased competition on DSM, and recommendations for how to provide utilities with incentives to implement DSM. On behalf of the Colorado Office of Energy Conservation. June 1995.

Colorado Public Utilities Commission (5R-071E): Oral testimony on the Commission's integrated resource planning rules. On behalf of the Colorado Office of Energy Conservation. July 1995.

Colorado Public Utilities Commission (3I-098E): Direct testimony on the Public Service Company of Colorado's DSM programs and integrated resource plans. On behalf of the Colorado Office of Energy Conservation. April 1994.

Delaware Public Service Commission (Docket No. 96-83): Filed comments regarding the Investigation of Restructuring the Electricity Industry in Delaware (Tellus Institute Study No. 96-99). On behalf of the Staff of the Delaware Public Service Commission. November 1996.

Colorado Public Utilities Commission (Docket No. 96Q-313E): Filed comments in response to the Questionnaire on Electricity Industry Restructuring (Tellus Institute Study No. 96-130-A3). On behalf of the Colorado Governor's Office of Energy Conservation. October 1996.

State of Vermont Public Service Board (Docket No. 5854): Filed expert report (Tellus Institute Study No. 95-308) regarding the Investigation into the Restructuring of the Electric Utility Industry in Vermont. On behalf of the Vermont Department of Public Service. March 1996.

Pennsylvania Public Utility Commission (Docket No. I-00940032): Filed comments (Tellus Institute Study No. 95-260) regarding an Investigation into Electric Power Competition. On behalf of The Pennsylvania Office of Consumer Advocate. November 1995.

New Jersey Board of Public Utilities (Docket No. EX94120585Y): Initial and reply comments ("Achieving Efficiency and Equity in the Electricity Industry Through Unbundling and Customer Choice," Tellus Institute Study No. 95-029-A3) regarding an investigation into the future structure of the electric power industry. On behalf of the New Jersey Division of Ratepayer Advocate. September 1995.

ARTICLES

Woolf, T., E. Malone, C. Neme, R. LeBaron. 2014. "Unleashing Energy Efficiency." *Public Utilities Fortnightly,* October, 30-38.

Woolf, T., A. Sommer, J. Nielson, D. Berry, R. Lehr. 2005. "Managing Electricity Industry Risk with Clean and Efficient Resources." *The Electricity Journal* 18 (2): 78–84.

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Woolf, T. 2001. "What's New With Energy Efficiency Programs." *Energy & Utility Update, National Consumer Law Center*: Summer 2001.

Woolf T., B. Biewald. 2000. "Electricity Market Distortions Associated With Inconsistent Air Quality Regulations." *The Electricity Journal* 13 (3): 42–49.

Ackerman, F., B. Biewald, D. White, T. Woolf, W. Moomaw. 1999. "Grandfathering and Coal Plant Emissions: the Cost of Cleaning Up the Clean Air Act." *Energy Policy* 27 (15): 929–940.

Biewald, B., D. White, T. Woolf. 1999. "Follow the Money: A Method for Tracking Electricity for Environmental Disclosure." *The Electricity Journal* 12 (4): 55–60.

Woolf, T., B. Biewald. 1998. "Efficiency, Renewables and Gas: Restructuring As if Climate Mattered." *The Electricity Journal* 11 (1): 64–72.

Woolf, T., J. Michals. 1996. "Flexible Pricing and PBR: Making Rate Discounts Fair for Core Customers." *Public Utilities Fortnightly,* July 1996.

Woolf, T., J. Michals. 1995. "Performance-Based Ratemaking: Opportunities and Risks in a Competitive Electricity Industry." *The Electricity Journal* 8 (8): 64–72.

Woolf, T. 1994. "Retail Competition in the Electricity Industry: Lessons from the United Kingdom." *The Electricity Journal* 7 (5): 56–63.

Woolf, T. 1994. "A Dialogue About the Industry's Future." *The Electricity Journal* 7 (5).

Woolf, T., E. D. Lutz. 1993. "Energy Efficiency in Britain: Creating Profitable Alternatives." *Utilities Policy* 3 (3): 233–242.

Woolf, T. 1993. "It is Time to Account for the Environmental Costs of Energy Resources." *Energy and Environment* 4 (1): 1–29.

Woolf, T. 1992. "Developing Integrated Resource Planning Policies in the European Community." *Review of European Community & International Environmental Law* 1 (2) 118–125.

PRESENTATIONS

Woolf, T., M. Whited. 2016. "Show Me the Numbers: A Framework for Balanced Distributed Solar Policies." Presentation for Consumers Union Webinar, December 2016.

Woolf, T. 2016. "Show Me the Numbers: Balancing Solar DG with Consumer Protection." Public workshop on solar distributed generation for the Federal Trade Commission, June 2016.

Woolf, T. 2016. "Rate Designs for Distributed Generation: State Activities & A New Framework." Presentation at the NASUCA 2016 Mid-Year Meeting, June 2016.

Woolf, T., M. Whited. 2016. "3rd Annual 21st Century Electricity System Workshop – Implications of Different Rate Designs." Presentation at the Advanced Energy Economy Institute, April 2016.

Woolf, T., M. Whited. 2016. "Decoupling in Pennsylvania: Advantages, Disadvantages, and Design Issues." Presentation to Pennsylvania Decoupling Stakeholders, February 2016.

Woolf, T. 2016. "Earnings Impact Mechanisms: Energy Efficiency." Presentation at the New York REV Technical Conference, January 2016.

Lowry, M. N., T. Woolf. 2015. "Performance-Based Regulation in a High Distributed Energy Resources Future." Webinar on January 2016.

Woolf, T. 2015. "Performance Incentive Mechanisms: A Catalyst for Change." Webinar for Power Sector Transformation Group, December 2015.

Woof, T. 2015. "Energy Efficiency Valuation: Boogie Men, Time Warps, and other Terrifying Pitfalls." Presentation at ACEEE Conference on Energy Efficiency as a Resource, September 2015.

Woolf, T., M. Whited, A. Napoleon. 2015. "Thoughts on How to Design Clean Energy Performance Incentive Mechanisms." Webinar for the Western Clean Energy Advocates, April 2015.

Woolf, T. 2015. "Properly Valuing the Benefits and Costs of Energy Efficiency." Presentation at the 2015 National Efficiency Advocates Meeting, April 2015.

Woolf, T. 2015. "Non-Energy Benefits & Efficiency Program Screening." Presentation for Georgia DSM Work Group, March 2015.

Woolf, T. 2014. "Performance Incentive Mechanisms And Their Role in New Regulatory Models." Presentation at Acadia Center Conference, Envisioning Our Energy Future, December 2014.

Woolf, T., M. Whited., A. Napoleon. 2014. "Guiding Utility Performance: A Handbook for Regulators." Webinar for the Western Interstate Energy Board, December 2014.

Woolf, T. 2014. "Planning for Distributed Energy Resources." Presentation for Advanced Energy Economy Webinar, November 2014.

Woolf, T. 2014. "Benefit-Cost Analysis for Distributed Energy Resources in New York: A Framework for Accounting for All Relevant Costs and Benefits." Presentation to NARUC ERE Committee, November 2014.

Woolf, T. 2014. "Presenting the Full Value of Energy Efficiency: Creating a Better Message." Presentation at Sierra Club Beyond Coal Conference, October 2014.

Woolf, T., C. Neme. 2014. "Regulatory Policies to Support Energy Efficiency in Virginia." Presentation for the 2014 Virginia Energy Efficiency Workshop, October 2014.

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Woolf, T. 2014. "Performance Incentive Mechanisms: Digging Deeper Into Performance-Based Regulation." Presentation for National Governor's Association Conference: Utility Business Models That Align with State Clean Energy Goals, September 2014.

Woolf, T. 2014. "The Resource Value Framework: Reforming Energy Efficiency Cost-Effectiveness Screening." Presentation at the ACEEE Summer Study, August 2014.

Woolf, T. 2014. "Cost-Effectiveness of Demand Response." Presentation at MADRI Working Group Meeting #34, July 2014.

Woolf, T. 2014. "Time to Overhaul Our Energy Efficiency Screening Practices." Presentation for U.S. Environmental Protection Agency Energy Efficiency Cost-Effectiveness Webinar, January 2014.

Woolf, T. 2013. "Survey of Energy Efficiency Screening Practices in the Northeast and Mid-Atlantic." Presentation for Northeast Energy Efficiency Partnerships EM&V Forum Annual Public Meeting, December 2013.

Woolf, T. 2013. "Recommendations for Reforming Energy Efficiency Cost-Effectiveness Screening in the United States." Presentation at the National Association of Regulatory Commissioners Annual Meeting, November 2013.

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Woof, T. 2013. "Energy Efficiency Screening: Challenges and Opportunities." Presentation for NARUC Summer Meeting Consumer Affairs Panel, July 2013.

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Woolf, T. 2013. “Energy Efficiency Screening: Accounting for ‘Other Program Impacts’ & Environmental Compliance Costs.” Presentation for Regulatory Assistance Project Webinar, March 2013.

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Woolf, T. 2011. “A Regulator’s Perspective on Energy Efficiency.” Presentation at the Efficiency Maine Symposium *In Pursuit of Maine’s Least-Cost Energy*, September 2011.

Woolf, T. 2010. “Bill Impacts of Energy Efficiency Programs: The Importance of Analyzing and Managing Rate and Bill Impacts.” Presentation at the Energy in the Northeast Conference, Law Seminar International, September 2010.

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Woolf, T. 2010. “Bill Impacts of Energy Efficiency Programs.” Presentation to the Energy Resources and Environment Committee at the NARUC Winter Meetings, February 2010.

Woolf, T. 2009. “Price-Responsive Demand in the New England Wholesale Energy Market: Description of NECPUC’s Limited Supply-Side Proposal.” Presentation at the NEPOOL Markets Committee Meeting, November 2009.

Woolf, T. 2009. “Demand Response in the New England Wholesale Energy Market: How Much Should We Pay for Demand Resources?” Presentation at the New England Electricity Restructuring Roundtable, October 2009.

Woolf, T. 2008. “Promoting Demand Resources in Massachusetts: A Regulator’s Perspective.” Presentation at the Energy Bar Association, Northeast Chapter Meeting, June 2008.

Woolf, T. 2008. “Turbo-Charging Energy Efficiency in Massachusetts: A DPU Perspective.” Presentation at the New England Electricity Restructuring Roundtable, April 2008.

Woolf T. 2002. “A Renewable Portfolio Standard for New Brunswick.” Presentation to the New Brunswick Market Design Committee, January 10, 2002.

Woolf, T. 2001. “Potential for Wind and Renewable Resource Development in the Midwest.” Presentation at WINDPOWER 2001 in Washington DC, June 7, 2001.

Woolf T. 1999. “Challenges Faced by Clean Generation Resources Under Electricity Restructuring.” Presentation at the Symposium on the Changing Electric System in Florida and What it Means for the Environment in Tallahassee, FL, November 1999.

Woolf, T. 2000. “Generation Information Systems to Support Renewable Portfolio Standards, Generation Performance Standards and Environmental Disclosure.” Presentation at the Massachusetts Restructuring Roundtable on behalf of the Union of Concerned Scientists, March 2000.

Woolf, T. 1998. “New England Tracking System Project: An Electricity Tracking System to Support a Wide Range of Restructuring-Related Policies.” Presentation at the Ninth Annual Energy Services Conference and Exposition in Orlando, FL, December 1998.

Woolf, T. 2000. “Comments of the Citizens Action Coalition of Indiana.” Presentation at Workshop on Alternatives to Traditional Generation Resources, June 2000.

Woolf, T. 1996. “Overview of IRP and Introduction to Electricity Industry Restructuring.” Training session provided to the staff of the Delaware Public Service Commission, April 1996.

Woolf, T. 1995. “Competition and Regulation in the UK Electric Industry.” Presentation at the Illinois Commerce Commission's workshop on Restructuring the Electric Industry, August 1995.

Woolf, T. 1995. “Competition and Regulation in the UK Electric Industry.” Presentation at the British Columbia Utilities Commission Electricity Market Review, February 1995.

Resume dated March 2018

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PROFESSIONAL EXPERIENCE

Synapse Energy Economics, Cambridge MA. *Principal Associate,* 2017 – present*, Senior Associate,* 2015 – 2017*, Associate*, 2012 – 2015

Conduct research, author reports, and assist in preparation of expert testimony. Consult on issues related to distributed energy resources, rate design, cost-benefit analysis, integrated resource planning, utility regulation, water use and conservation, and market power.

University of Wisconsin - Madison, Department of Agricultural and Applied Economics, Madison, WI. *Teaching Assistant – Environmental Economics*, 2011 – 2012

Developed teaching materials and led discussions on cost-benefit analysis, carbon taxes and cap-and-trade programs, management of renewable and non-renewable resources, and other topics.

Public Service Commission of Wisconsin, Water Division, Madison, WI. *Program and Policy Analyst - Intern*, Summer 2009

Researched water conservation programs nationwide to develop a proposal for Wisconsin's state conservation program. Developed spreadsheet model to calculate avoided costs of water conservation in terms of energy savings and avoided emissions.

Synapse Energy Economics, Cambridge, MA. *Communications Manager*, 2005 – 2008

Developed technical proposals for state and federal agencies, environmental and public interest groups, and businesses. Edited reports on energy efficiency, integrated resource planning, greenhouse gas regulations, renewable resources, and other topics.

EDUCATION

University of Wisconsin, Madison, WI
Master of Arts in Agricultural and Applied Economics, 2012.
Certificate in Energy Analysis and Policy.
National Science Foundation Fellow.

University of Wisconsin, Madison, WI
Master of Science in Environment and Resources, 2010.
Certificate in Humans and the Global Environment (CHANGE).
Nelson Distinguished Fellowship.

Southwestern University, Georgetown, TX
Bachelor of Arts in International Studies, *Magna cum laude,* 2003.

ADDITIONAL SKILLS

- Econometric Modeling – Linear and nonlinear modeling including time-series, panel data, logit, probit, and discrete choice regression analysis
- Nonmarket Valuation Methods for Environmental Goods – Hedonic valuation, travel cost method, and contingent valuation
- Cost-Benefit Analysis
- Input-Output Modeling for Regional Economic Analysis

FELLOWSHIPS AND AWARDS

- Winner, M. Jarvin Emerson Student Paper Competition, Journal of Regional Analysis and Policy, 2010
- Fellowship, National Science Foundation Integrative Graduate Education and Research Traineeship (IGERT), University of Wisconsin – Madison, 2009
- Nelson Distinguished Fellowship, University of Wisconsin – Madison, 2008

PUBLICATIONS

Fisher, J., M. Whited, T. Woolf, D. Goldberg. 2018. *Utility Investments for Market Transformation: How Utilities Can Help Achieve Energy Policy Goals.* Prepared by Synapse Energy Economics for Energy Foundation.

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Whited, M., A. Horowitz, T. Vitolo, W. Ong, T. Woolf. 2017. *Distributed Solar in the District of Columbia: Policy Options, Potential, Value of Solar, and Cost-Shifting*. Synapse Energy Economics for the Office of the People's Counsel for the District of Columbia.

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Woolf, T., M. Whited, P. Knight, T. Vitolo, K. Takahashi. 2016. *Show Me the Numbers: A Framework for Balanced Distributed Solar Policies.* Synapse Energy Economics for Consumers Union.

Whited, M., T. Woolf, J. Daniel. 2016. *Caught in a Fix: The Problem with Fixed Charges for Electricity*. Synapse Energy Economics for Consumers Union.

Lowry, M. N., T. Woolf, M. Whited, M. Makos. 2016. *Performance-Based Regulation in a High Distributed Energy Resources Future*. Pacific Economics Group Research and Synapse Energy Economics for Lawrence Berkley National Laboratory.

Woolf, T., M. Whited, A. Napoleon. 2015-2016. *Comments and Reply Comments in the New York Public Service Commission Case 14-M-0101: Reforming the Energy Vision*. Comments related to Staff's (a) a benefit-costs analysis framework white paper, (b) ratemaking and utility business models white paper, and (c) Distributed System Implementation Plan guide. Prepared by Synapse Energy Economics on behalf of Natural Resources Defense Council and Pace Energy and Climate Center.

Luckow, P., B. Fagan, S. Fields, M. Whited. 2015. *Technical and Institutional Barriers to the Expansion of Wind and Solar Energy.* Synapse Energy Economics for Citizens' Climate Lobby.

Wilson, R., M. Whited, S. Jackson, B. Biewald, E. A. Stanton. 2015. *Best Practices in Planning for Clean Power Plan Compliance.* Synapse Energy Economics for the National Association of State Utility Consumer Advocates.

Whited, M., T. Woolf, A. Napoleon. 2015. *Utility Performance Incentive Mechanisms: A Handbook for Regulators*. Synapse Energy Economics for the Western Interstate Energy Board.

Stanton, E. A., S. Jackson, B. Biewald, M. Whited. 2014. *Final Report: Implications of EPA's Proposed "Clean Power Plan."* Synapse Energy Economics for the National Association of State Utility Consumer Advocates.

Peterson, P., S. Fields, M. Whited. 2014. *Balancing Market Opportunities in the West: How participation in an expanded balancing market could save customers hundreds of millions of dollars.* Synapse Energy Economics for the Western Grid Group.

Woolf, T., M. Whited, E. Malone, T. Vitolo, R. Hornby. 2014. *Benefit-Cost Analysis for Distributed Energy Resources: A Framework for Accounting for All Relevant Costs and Benefits.* Synapse Energy Economics for the Advanced Energy Economy Institute.

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Stanton, E. A., M. Whited, F. Ackerman. 2014. *Estimating the Cost of Saved Energy in Utility Efficiency Programs.* Synapse Energy Economics for the U.S Environmental Protection Agency.

Ackerman, F., M. Whited, P. Knight. 2014. "Would banning atrazine benefit farmers?" *International Journal of Occupational and Environmental Health* 20 (1): 61–70.

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Whited, M., F. Ackerman, S. Jackson. 2013. *Water Constraints on Energy Production: Altering our Current Collision Course.* Synapse Energy Economics for Civil Society Institute.

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Hurley, D., P. Peterson, M. Whited. 2013. *Demand Response as a Power System Resource: Program Designs, Performance, and Lessons Learned in the United States.* Synapse Energy Economics for Regulatory Assistance Project.

Whited, M., D. White, S. Jackson, P. Knight, E.A. Stanton. 2013. *Declining Markets for Montana Coal*. Synapse Energy Economics for Northern Plains Resource Council.

Woolf, T., M. Whited, T. Vitolo, K. Takahashi, D. White. 2012. *Indian Point Energy Center Replacement Analysis: A Plan for Replacing the Nuclear Plant with Clean, Sustainable, Energy Resources.* Synapse Energy Economics for National Resources Defense Council and Riverkeeper.

Whited, M., K. Charipar, G. Brown. *Demand Response Potential in Wisconsin.* Nelson Institute for Environmental Studies, Energy Analysis & Policy Capstone for the Wisconsin Public Service Commission.

Whited, M. 2010. "Economic Impacts of Irrigation Water Transfers in Uvalde County, Texas." *Journal of Regional Analysis and Policy* 40 (2): 160–170.

Grabow, M., M. Hahn and M. Whited. 2010. *Valuing Bicycling's Economic and Health Impacts in Wisconsin*. Nelson Institute for Environmental Studies, Center for Sustainability and the Global Environment (SAGE) for State Representative Spencer Black.

Whited, M., D. Bernhardt, R. Deitchman, C. Fuchsteiner, M. Kirby, M. Krueger, S. Locke, M. Mcmillen, H. Moussavi, T. Robinson, E. Schmitz, Z. Schuster, R. Smail, E. Stone, S. Van Egeren, H. Yoshida, Z. Zopp. 2009. *Implementing the Great Lakes Compact: Wisconsin Conservation and Efficiency Measures Report.* Department of Urban and Regional Planning, University of Wisconsin-Madison, Extension Report 2009-01.

Whited, M. 2009. *2009 Wisconsin Water Fact Sheet*. Public Service Commission of Wisconsin.

Whited, M. 2003. *Gender, Water, and Trade*. International Gender and Trade Network Washington, DC.

TESTIMONY

Rhode Island Public Utilities Commission (Docket No. 4783): Direct testimony of Tim Woolf and Melissa Whited regarding National Grid's Advanced Metering Functionality Pilot. On behalf of the Rhode Island Division of Public Utilities and Carriers. February 22, 2018.

Virginia State Corporation Commission (Case No. PUR-2017-00044): Direct testimony of Melissa Whited regarding Rappahannock Electric Cooperative's proposed increases to fixed charges for residential customers and small business customers. On behalf of Sierra Club. September 19, 2017.

California Public Utilities Commission (Application 17-01-020, 17-01-021, and 17-01-022): Joint opening testimony with Max Baumhefner and Katherine Stainken on fast charging infrastructure and rates; joint opening testimony with Max Baumhefner and Joel Espino on medium and heavy-duty and fleet charging infrastructure and commercial EV rates; joint opening testimony with Max Baumhefner and Chris King on residential charging infrastructure and rates. Rebuttal testimony on public fast charging rate design, commercial EV rate design, and residential EV rate design. On behalf of Natural Resources Defense Council, the Greenlining Institute, Plug In America, the Coalition of California Utility Employees, Sierra Club, and the Environmental Defense Fund. July 25, August 1, August 7, and September 5, 2017.

New York Public Service Commission (Case 17-E-0238): Direct and rebuttal testimony of Tim Woolf and Melissa Whited regarding Earnings Adjustment Mechanisms proposed by National Grid. On behalf of Advanced Energy Economy Institute. August 25 and September 15, 2017.

Utah Public Service Commission (Docket No. 14-035-114): Direct testimony of Melissa Whited regarding Pacificorp's proposed rates for customers with distributed generation. On behalf of Utah Clean Energy. June 8, 2017.

Texas Public Utilities Commission (SOAH Docket No. 473-17-1764, PUC Docket No. 46449): Cross-rebuttal testimony evaluating Southwestern Electric Power Company's proposed revisions to its Distributed Renewable Generation tariff. On behalf of Sierra Club and Dr. Lawrence Brough. May 19, 2017.

Massachusetts Department of Public Utilities (Docket No. 17-05): Direct and surrebuttal testimony of Tim Woolf and Melissa Whited regarding performance-based regulation, the monthly minimum reliability contribution, storage pilots, and rate design in Eversource's petition for approval of rate increases and a performance-based ratemaking mechanism. On behalf of Sunrun and the Energy Freedom Coalition of America, LLC. April 28, 2017 and May 26, 2017.

Public Utilities Commission of Hawaii (Docket No. 2015-0170): Direct testimony regarding Hawaiian Electric Light Company's proposed performance incentive mechanisms. On behalf of the Division of Consumer Advocacy. April 28, 2017.

Massachusetts Department of Public Utilities (Docket No. 15-155): Joint direct and rebuttal testimony with T. Woolf regarding National Grid's rate design proposal. On behalf of Energy Freedom Coalition of America, LLC. March 18, 2016 and April 28, 2016.

Federal Energy Regulatory Commission (Docket No. EC13-93-000): Affidavit regarding potential market power resulting from the acquisition of Ameren generation by Dynegy. On behalf of Sierra Club. August 16, 2013.

Wisconsin Senate Committee on Clean Energy: Joint testimony with M. Grabow regarding the importance of clean transportation to Wisconsin's public health and economy. February 2010.

TESTIMONY ASSISTANCE

Colorado Public Utilities Commission (Proceeding No. 16AL-0048E): Answer testimony of Tim Woolf regarding Public Service Company of Colorado's rate design proposal. On behalf of Energy Outreach Colorado. June 6, 2016.

Nevada Public Utilities Commission (Docket Nos. 15-07041 and 15-07042): Direct testimony on NV Energy's application for approval of a cost of service study and net metering tariffs. On behalf of The Alliance for Solar Choice. October 27, 2015.

Missouri Public Service Commission (Case No. ER-2014-0370): Direct and surrebuttal testimony on the topic of Kansas City Power and Light's rate design proposal. On behalf of Sierra Club. April 16, 2015 and June 5, 2015.

Wisconsin Public Service Commission (Docket No. 05-UR-107): Direct and surrebuttal testimony of Rick Hornby regarding Wisconsin Electric Power Company rate case. On behalf of The Alliance for Solar Choice. August 28, 2014 and September 22, 2014.

Maine Public Utilities Commission (Docket No. 2013-00519): Direct testimony of Richard Hornby and Martin R. Cohen on GridSolar's smart grid coordinator petition. On behalf of the Maine Office of the Public Advocate. August 28, 2014.

Maine Public Utilities Commission (Docket No. 2013-00168): Direct and surrebuttal testimony of Tim Woolf regarding Central Maine Power's request for an alternative rate plan. December 12, 2013 and March 21, 2014.

Massachusetts Department of Public Utilities (Docket No. 14-04): Comments of Massachusetts Department of Energy Resources on investigation into time varying rates. On behalf of the Massachusetts Department of Energy Resources. March 10, 2014.

State of Nevada, Public Utilities Commission of Nevada (Docket No. 13-07021): Direct testimony of Frank Ackerman regarding the proposed merger of NV Energy, Inc. and MidAmerican Energy Holdings Company. On behalf of the Sierra Club. October 24, 2013.

PRESENTATIONS

Whited, M. 2016. “Energy Policy for the Future: Trends and Overview.” Presentation to the National Conference of State Legislators’ Capitol Forum, Washington, DC, December 8.

Whited, M. 2016. “Ratemaking for the Future: Trends and Considerations.” Presentation to the Midwest Governors’ Association, St. Paul, MN, July 14.

Whited, M. 2016. “Performance Based Regulation.” Presentation to the NARUC Rate Design Subcommittee. September 12.

Whited, M. 2016. “Demand Charges: Impacts and Alternatives (A Skeptic’s View).” EUCI 2nd Annual Residential Demand Charges Summit, Phoenix, AZ, June 7.

Whited, M. 2016. “Performance Incentive Mechanisms.” Presentation to the National Governors Association, Wisconsin Workshop, Madison WI, March 29.

Whited, M., T. Woolf. 2016. “Caught in a Fix: The Problem with Fixed Charges for Electricity.” Webinar presentation sponsored by Consumers Union, February.

Whited, M. 2015. “Performance Incentive Mechanisms.” Presentation to the National Governors Association, Learning Lab on New Utility Business Models & the Electricity Market Structures of the Future, Boston, MA, July 28.

Whited, M. 2015. “Rate Design: Options for Addressing NEM Impacts.” Presentation to the Utah Net Energy Metering Workgroup, Workshop 4, Salt Lake City, UT, July 8.

Whited, M. 2015. “Performance Incentive Mechanisms.” Presentation to the e21 Initiative, St. Paul, MN, May 29.

Whited, M., F. Ackerman. 2013. “Water Constraints on Energy Production: Altering our Current Collision Course.” Webinar presentation sponsored by Civil Society Institute, September 12.

Whited, M., G. Brown, K. Charipar. 2011. “Electricity Demand Response Programs and Potential in Wisconsin.” Presentation to the Wisconsin Public Service Commission, April.

Whited, M. 2010. “Economic Impact of Irrigation Water Transfers in Uvalde County, Texas.” Presentation at the Mid-Continent Regional Science Association’s 41st Annual Conference/IMPLAN National User’s 8th Biennial Conference in St. Louis, MO, June

Whited, M., M. Grabow, M. Hahn.2009. “Valuing Bicycling’s Economic and Health Impacts in Wisconsin.” Presentation before the Governor’s Coordinating Council on Bicycling, December.

Whited, M., D. Sheard. 2009. “Water Conservation Initiatives in Wisconsin.” Presentation before the Waukesha County Water Conservation Coalition Municipal Water Conservation Subgroup, July.

Resume dated March 2018

Direct Testimony of Tim Woolf and Melissa Whited
RIDPUC Docket No. 4770
Exhibit TW/MW-3

Assumptions for the Benefit-Cost Analysis
Used to Determine PIM Incentive Levels

Contents

1. Introduction

Ideally, performance incentives should be proportionate to the importance of the performance goal to customers, and they should not exceed the net benefits to customers (including both quantified and unquantified benefits). We applied this principle by estimating the benefits and the costs associated with achieving each PIM, and then assigning a portion of net benefits to the utility in the form of an incentive payment.

Below we describe the assumptions and data sources that we relied upon to calculate the benefits and costs associated with meeting each PIM. Additional details on the assumptions and calculations are provided in Exhibit TW/MW-4, which is the Excel workbook used to make the calculations.

2. Avoided Costs

Avoided Generation Capacity Costs

Daymark estimated avoided generation capacity costs for 2019–2038 using Daymark's proprietary capacity model and the cost of new entry (CONE) for Forward Capacity Auction (FCA) clearing prices. These cost estimates rely on the 2017 CELT Load Forecast for 2016 through 2026, with projections for load between 2027–2038 and assuming a 14.3 percent planning reserve margin.

Because FCAs 10, 11, and 12 have already been completed, the avoided costs for 2019–2021 are assumed to be zero. While there could be a small benefit through reconfiguration auctions, these benefits are assumed to be negligible.

Table 1 below shows avoided generation costs in $/MW-year for 2019 through 2030 in nominal dollars. We note that these values are substantially lower than those assumed by the Company (which were based on AESC 2015).

Avoided Transmission Capacity Costs

Avoided transmission costs were estimated by Daymark for 2019-2038. These cost estimates rely on the 2017 CELT Load Forecast for 2016 through 2026, with projections for load between 2027–2038, Section II Open Access Tariff Rates, and Planning Procedure PP04—Procedure for Pool-Supported PTF Cost Review. The methodology assumes that load is reduced only for Rhode Island and not for the rest of the ISO New England system. Avoided transmission costs in $/MW-year for 2019 through 2030 are shown in the table below in nominal dollars. Note that a MW reduction for only one month would be associated with a benefit of 8 percent of the annual ($/MW-year) value.

Avoided Distribution Costs

Avoided distribution capacity costs were based on National Grid's Energy Efficiency Screening tool. Table 1 below provides these values for 2019 through 2030 (assuming 2 percent inflation). These values are provided in $/MW-year terms.

Avoided Peak Hour Energy Costs

Avoided cost estimates for peak hour energy reductions were developed by Daymark using Daymark's Energy Model. These values are based on modeled locational marginal prices and do not assume any change in the LMP due to load reduction.

The average value of reducing energy consumption during the peak load hour was calculated assuming a 2.5 percent reduction in peak load. Table 1 below shows the values in $/MWh for 2019–2030.

Avoided Greenhouse Gas Emissions

We used the same estimate for the value of avoided greenhouse gas emissions as used by National Grid, which come from the 2015 Avoided Energy Supply Cost study, Exhibit 4-7. These values in $/short ton are provided below for 2019–2030.

Table 1. Avoided Costs for Years 2019–2030

Year	Avoided Capacity Costs ($/MW-yr)	Avoided Transmission Costs ($/MW-yr)	Avoided Distribution Costs ($/MW-yr)	Avoided Peak Hour Energy Costs ($/MWh)	Non-Embedded CO_2 Cost ($/short ton)
2019	0	$124,913	$80,000	$80	$94
2020	0	$133,170	$84,897	$82	$95
2021	0	$141,612	$86,595	$74	$95
2022	$55,042	$150,390	$88,326	$76	$94
2023	$55,936	$159,312	$90,093	$77	$93
2024	$62,393	$168,380	$91,895	$83	$92
2025	$64,297	$177,593	$93,733	$87	$91
2026	$69,950	$186,950	$95,607	$94	$90
2027	$75,749	$196,453	$97,520	$96	$89
2028	$84,529	$206,100	$99,470	$101	$88
2029	$102,516	$215,893	$101,459	$110	$87
2030	$97,070	$225,830	$103,489	$116	$85

3. Discount Rate

To estimate the net benefits of each PIM, we included societal benefits consistent with the Rhode Island Benefit-Cost Framework. Therefore, we applied a societal discount rate of 3 percent (equivalent to approximately 5.5 percent nominal).

4. Peak Coincidence Factors

Not all reductions in demand will have the same impact on the grid. For example, a reduction in the monthly peak demand for the month of April would provide a benefit in terms of avoided transmission costs for that month, but it would not provide a benefit in terms of forward capacity market (FCM) costs, unless it was assumed to be available in the annual peak hour as well. For each PIM, we made assumptions regarding the extent to which measures implemented for one PIM would help to avoid annual peak demand, monthly transmission peak demand, and local distribution peak demand (that is, at the feeder or substation level).

These assumptions are expressed in terms of assumed coincidence factors, which are then multiplied by the targets to develop assumed MW reductions for each type of demand reduction. These coincidence factors are shown in the table below for the System Efficiency and distributed energy resource PIMs.

Table 2. Assumed Peak Demand Coincidence for Measures Implemented to Achieve Each PIM

Performance Incentive Mechanism	FCM Peak Coincidence	Transmission Peak Coincidence	Distribution Peak Coincidence
Transmission Peak Demand Reduction	0%	100%	5%
FCM Peak Demand Reduction	100%	8%	20%
Demand Response - Residential	100%	25%	80%
Demand Response - C&I	100%	25%	80%
Electric Heat Initiative	0%	0%	0%
Electric Vehicle Initiative	0%	0%	0%
Behind-the-Meter Storage	80%	30%	40%
Utility-Scale Storage	90%	90%	90%
Non-Wires Alternatives	60%	30%	100%

5. Assumed Costs to Customers of Implementing PIM

The cost of an initiative or technology implemented to achieve a PIM will have a large impact on the net benefits that the PIM provides. For the FCM Peak and Transmission Peak PIMs we assumed that there will be no additional cost to the customers, because the Company has not requested recovery of any such costs in this rate case.

For most of the PIM initiatives (e.g., residential demand response, behind-the-meter storage), the forward-going costs are not known at this time. Our cost estimates are based on our understanding of the general cost-effectiveness of the relevant technology or program. Although these costs are not known with great certainty, the majority of these PIMs are designed to provide shared savings so that the Company is rewarded only when the PIM is cost-effective.

Our assumptions regarding the costs of achieving the PIM targets are expressed as a percent of benefits in the table below.

Table 3. Assumed Costs to Customers as Percent of Benefits for Each PIM

Performance Incentive Mechanism	Assumed Costs as % of Benefits
Transmission Peak Demand Reduction	0%
FCM Peak Demand Reduction	0%
Demand Response - Residential	90%
Demand Response - C&I	70%
Electric Heat Initiative	71%
Electric Vehicle Initiative	80%
Behind-the-Meter Storage	90%
Utility-Scale Storage	90%
Non-Wires Alternatives	90%

6. PIM Incentives

Our approach to calculating the PIM incentives to provide to the Company includes the following steps.

First, we determined the quantified net benefits for each of the PIM initiatives. These are based on all of the assumptions described above.

Second, we determined how the quantified net benefits should be shared between the Company and customers. For each PIM, we propose that the net benefits be shared on a 50/50 basis.

Third, we divided the quantified net benefits by the expected value of a basis point in each year, using the Company's assumptions. These assumptions may change if the revenue requirement is changed from the Company's assumption. The table below provides the assumed value of a basis point.

Table 4. Assumed Value per Basis Point ($/bp)

2019	2020	2021
$59,493	$60,526	$63,602

Fourth, we identified additional unquantified benefits associated with each of the PIMs. We assumed these to be in the form of (a) improved reliability or resilience; (b) other fuel benefits; (c) market innovation or transformation benefits; or (d) low-income benefits. We chose the number of basis points for each PIM based upon the type and number of unquantified benefits, and the importance of each unquantified benefit in light of Docket 4600 goals and state energy policies. The table below shows the categories of likely unquantified benefits and the basis points assigned to reflect these benefits.

Table 5. Basis Points for Unquantified Benefits

Performance Incentive Mechanism	Unquantified Benefits	2019 Med (bps)	2019 High (bps)	2020 Med (bps)	2020 High (bps)	2021 Med (bps)	2021 High (bps)
Transmission Peak Reduction		-	-	-	-	-	-
FCM Peak Demand Reduction		-	-	-	-	-	-
Demand Response - Residential	Reliability, Market Transformation	1	1	1	1	1	1
Demand Response - C&I	Reliability, Market Transformation	1	1	1	1	1	1
Electric Heat Initiative	Reliability, Market Transformation, Low Income Benefits	1	2	1	2	1	2
Electric Vehicle Initiative	Market Transformation	2	3	2	3	2	3
Behind-the-Meter Storage	Reliability, Market Transformation	1	2	1	2	1	2
Utility-Scale Storage	Reliability, Market Transformation	1	2	1	2	1	2
Non-Wires Alternatives	Market Transformation	1	2	1	2	1	2
Low-Income: participation in PST	Low-Income Benefits	2	3	2	3	2	3
Low-Income: participation in A60	Low-Income Benefits	2	3	2	3	2	3
Provision of Customer Information	PST Support	1	-	-	-	-	-
Peak Demand Forecasting	PST Support	1	-	-	-	-	-

DIVISION EXHIBIT 4
SUBMITTED IN DOCKET 4770
ON BEHALF OF THE DIVISION OF PUBLIC UTILITIES AND CARRIERS

SUMMARY
Division Proposal

Performance Incentive Mechanism	Bps or Shared Savings	% to Company	Assumed Costs as % of Benefits	BCR	Target Units	Targets 2019 Medium	Targets 2019 High	Targets 2020 Medium	Targets 2020 High	Targets 2021 Medium	Targets 2021 High
System Efficiency											
Transmission Peak Demand Reduction	bps	50%	0%		MW below baseline	228	342	255	383	284	425
FCM Peak Demand Reduction	bps	50%	0%		MW below baseline	29	44	31	46	32	48
Distributed Energy Resources											
Demand Response - Residential	shared savings	50%	90%	1.11	Incremental MW	1	2	2	3	3	4
Demand Response - C&I	shared savings	50%	70%	1.43	Incremental MW	8	14	10	16	12	18
Electric Heat Initiative	shared savings	50%	71%	1.40	Incremental Tonnes CO2	464	556	580	696	595	714
Electric Vehicle Initiative	bps	50%	80%	1.25	Incremental Tonnes CO2	557	1,114	757	1,511	1,026	2,051
Behind-the-Meter Storage	shared savings	50%	90%	1.11	Incremental MW	1	2	1	2	1	2
Utility-Scale Storage	shared savings	50%	90%	1.11	Incremental MW	3	6	3	6	3	6
Non-Wires Alternatives	shared savings	50%	90%	1.11	Incremental MW	3	6	3	6	3	6
Existing Energy Efficiency		5%	33%	3.03	Incremental MW	30	37	35	38	34	38
PST Support Services											
Low-Income: participation in PST initiatives	bps				% LI cust in initiative	5	10	5	10	5	10
Low-Income: participation in LI rate	bps				% LI cust in initiative	4	8	4	8	4	8
Data Access	bps					Plan	--	--	--	--	--
Peak Demand Forecasting (one-year)	bps					Report	--	--	--	--	--
AMI Capabilities (2022)					# cust with TVR	--	--	--	--	--	--
Subtotal Existing PIMs											
Subtotal New PIMs											
Total PIMs											
					Monthly Tx MW	21	31	23	35	26	39

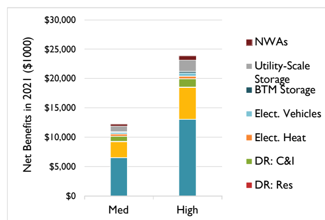
Performance Incentive Mechanism	Quantified Net Benefits ($1000) (before incentive) 2019 Medium	2019 High	2020 Medium	2020 High	2021 Medium	2021 High	Unquantified Benefits
System Efficiency							
Transmission Peak Demand Reduction	$4,765	$9,531	$5,599	$11,198	$6,531	$13,062	
FCM Peak Demand Reduction	$1,054	$2,108	$1,814	$3,629	$2,702	$5,405	
Distributed Energy Resources							
Demand Response - Residential	$9	$17	$27	$46	$59	$88	R&R; Mkt Trnsf
Demand Response - C&I	$206	$360	$491	$819	$881	$1,410	R&R; Mkt Trnsf
Electric Heat Initiative	$263	$315	$329	$395	$337	$405	R&R; Mkt Trnsf; LI
Electric Vehicle Initiative	$67	$134	$157	$313	$276	$551	Mkt Trnsf
Behind-the-Meter Storage	$38	$75	$87	$173	$146	$292	R&R; Mkt Trnsf
Utility-Scale Storage	$270	$539	$595	$1,190	$963	$1,926	R&R; Mkt Trnsf
Non-Wires Alternatives	$96	$192	$213	$425	$354	$709	Mkt Trnsf
Existing Energy Efficiency	$314,010	$314,010	$342,693	$342,693	$342,693	$342,693	
PST Support Services							
Low-Income: participation in PST initiatives							LI benefits
Low-Income: participation in LI rate							LI benefits
Data Access							PST Support
Peak Demand Forecasting (one-year)							PST Support
AMI Capabilities (2022)							
Subtotal Existing PIMs	$314,010	$314,010	$342,693	$342,693	$342,693	$342,693	
Subtotal New PIMs	$6,767	$13,271	$9,312	$18,187	$12,250	$23,848	
Total PIMs	$320,777	$327,281	$352,005	$360,880	$354,943	$366,541	

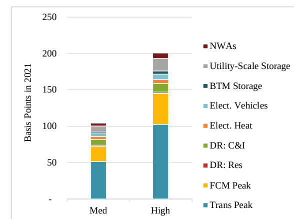
Performance Incentive Mechanism	Additional Bps for Unquantified Benefits 2019 Medium (bps)	2019 High (bps)	2020 Medium (bps)	2020 High (bps)	2021 Medium (bps)	2021 High (bps)
System Efficiency						
Transmission Peak Demand Reduction	-	-	-	-	-	-
FCM Peak Demand Reduction	-	-	-	-	-	-
Distributed Energy Resources						
Demand Response - Residential	1	1	1	1	1	1
Demand Response - C&I	1	1	1	1	1	1
Electric Heat Initiative	1	2	1	2	1	2
Electric Vehicle Initiative	2	3	2	3	2	3
Behind-the-Meter Storage	1	2	1	2	1	2
Utility-Scale Storage	1	2	1	2	1	2
Non-Wires Alternatives	1	2	1	2	1	2
Existing Energy Efficiency	-	-	-	-	-	-
PST Support Services						
Low-Income: participation in PST initiatives	2	3	2	3	2	3
Low-Income: participation in LI rate	2	3	2	3	2	3
Data Access	1	-	-	-	-	-
Peak Demand Forecasting (one-year)	1	-	-	-	-	-
AMI Capabilities (2022)						
Subtotal Existing PIMs						
Subtotal New PIMs						
Total PIMs						

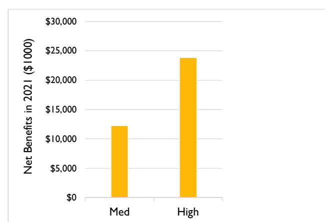
Performance Incentive Mechanism	Incentives (Basis Points) 2019 Medium (bps)	2019 High (bps)	2020 Medium (bps)	2020 High (bps)	2021 Medium (bps)	2021 High (bps)
System Efficiency						
Transmission Peak Demand Reduction	40	80	46	93	51	103
FCM Peak Demand Reduction	9	18	15	30	21	42
Distributed Energy Resources						
Demand Response - Residential	1	1	1	1	1	2
Demand Response - C&I	3	4	5	8	8	12
Electric Heat Initiative	3	5	4	5	4	5
Electric Vehicle Initiative	3	4	3	6	4	7
Behind-the-Meter Storage	1	3	2	3	2	4
Utility-Scale Storage	3	7	6	12	9	17
Non-Wires Alternatives	2	4	3	6	4	8
Existing Energy Efficiency	105	105	90	90	86	86
PST Support Services	-	-	-	-	-	-
Low-Income: participation in PST initiatives	2	3	2	3	2	3
Low-Income: participation in LI rate	2	3	2	3	2	3
Data Access	1	#VALUE!	-	-	-	-
Peak Demand Forecasting (one-year)	1	#VALUE!	-	-	-	-
AMI Capabilities (2022)						
Subtotal Existing PIMs	105	105	90	90	86	86
Subtotal New PIMs	71	#VALUE!	89	169	108	206
Total PIMs	176	#VALUE!	179	259	194	292
	16	27	24	41	32	55
	6	#VALUE!	4	6	4	6

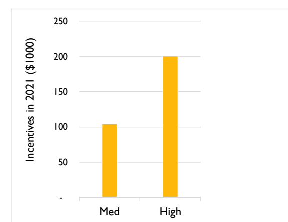
Performance Incentive Mechanism	Incentives ($1000) 2019 Medium ($1,000)	2019 High ($1,000)	2020 Medium ($1,000)	2020 High ($1,000)	2021 Medium ($1,000)	2021 High ($1,000)
System Efficiency						
Transmission Peak Demand Reduction	$2,383	$4,765	$2,800	$5,599	$3,266	$6,531
FCM Peak Demand Reduction	$527	$1,054	$907	$1,814	$1,351	$2,702
Distributed Energy Resources	$0	$0	$0	$0	$0	$0
Demand Response - Residential	$64	$68	$74	$83	$93	$108
Demand Response - C&I	$162	$239	$306	$470	$504	$769
Electric Heat Initiative	$191	$277	$225	$318	$232	$330
Electric Vehicle Initiative	$152	$245	$199	$338	$265	$467
Behind-the-Meter Storage	$78	$157	$104	$208	$137	$273
Utility-Scale Storage	$194	$389	$358	$716	$545	$1,090
Non-Wires Alternatives	$108	$215	$167	$334	$241	$482
Existing Energy Efficiency	$6,247	$6,247	$5,455	$5,455	$5,455	$5,455
PST Support Services	$0	$0	$0	$0	$0	$0
Low-Income: participation in PST initiatives	$119	$178	$121	$182	$127	$191
Low-Income: participation in LI rate	$119	$178	$121	$182	$127	$191
Data Access	$59	#VALUE!	$0	$0	$0	$0
Peak Demand Forecasting (one-year)	$59	#VALUE!	$0	$0	$0	$0
AMI Capabilities (2022)						
Subtotal Existing PIMs						
Subtotal New PIMs	$4,216	#VALUE!	$5,382	$10,244	$6,888	$13,132
Total PIMs						

Info for Charts	Net Benefits Med	Net Benefits High	Basis Pts Med	Basis Pts High
Trans Peak	$6,531	$13,062	51	103
FCM Peak	$2,702	$5,405	21	42
DR: Res	$59	$88	1	2
DR: C&I	$881	$1,410	8	12
Elect. Heat	$337	$405	4	5
Elect. Vehicles	$276	$551	4	7
BTM Storage	$146	$292	2	4
Utility-Scale Storage	$963	$1,926	9	17
NWAs	$354	$709	4	8
Energy Efficiency	#######	######	86	86
Total New PIMs	$12,250	$23,848	104	200









OUTCOMES
Division Proposal

Performance Incentive Mechanism	Target Units	FCM Savings (MW-yr)						Transmission Savings (MW-yr)					
		2019	2019	2020	2020	2021	2021	2019	2019	2020	2020	2021	2021
		Medium	High	Medium	High	Medium	High	Medium	High	Medium	High	Medium	High
System Efficiency													
Transmission Peak Demand Reduction	MW below baseline	0	0	0	0	0	0	10	21	12	23	13	26
FCM Peak Demand Reduction	MW below baseline	15	29	15	31	16	32	1	2	1	3	1	3
Distributed Energy Resources													
Demand Response - Residential	Incremental MW	1	2	3	5	6	9	0	1	1	1	2	2
Demand Response - C&I	Incremental MW	8	14	18	30	30	48	2	4	5	8	8	12
Electric Heat Initiative	Incremental Tonnes CO2	0	0	0	0	0	0	0	0	0	0	0	0
Electric Vehicle Initiative	Incremental Tonnes CO2	0	0	0	0	0	0	0	0	0	0	0	0
Behind-the-Meter Storage	Incremental MW	1	2	2	3	2	5	0	1	1	1	1	2
Utility-Scale Storage	Incremental MW	3	5	5	11	8	16	3	5	5	11	8	16
Non-Wires Alternatives	Incremental MW	2	4	4	7	5	11	1	2	2	4	3	5
Existing Energy Efficiency	Incremental MW	0	0	0	0	0	0	0	0	0	0	0	0
PST Support Services													
Low-Income: participation in PST initiatives	% LI cust in initiative	0	0	0	0	0	0	0	0	0	0	0	0
Low-Income: participation in LI rate	% LI cust in initiative	0	0	0	0	0	0	0	0	0	0	0	0
Provision of Customer Information	0	0	0	0	0	0	0	0	0	0	0	0	0
Peak Demand Forecasting (one-year)	0	0	0	0	0	0	0	0	0	0	0	0	0
AMI Capabilities (2022)	# cust with TVR	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal New PIMs	-	**29**	**56**	**47**	**87**	**68**	**121**	**18**	**35**	**26**	**50**	**35**	**66**

Performance Incentive Mechanism	Distribution Savings (MW-yr)						Energy Avg (MWh)					
	2019	2019	2020	2020	2021	2021	2019	2019	2020	2020	2021	2021
	Medium	High	Medium	High	Medium	High	Medium	High	Medium	High	Medium	High
System Efficiency												
Transmission Peak Demand Reduction	6	11	6	13	7	14	0	0	0	0	0	0
FCM Peak Demand Reduction	3	6	3	6	3	6	0	0	0	0	0	0
Distributed Energy Resources												
Demand Response - Residential	1	2	2	4	5	7	0	0	0	0	0	0
Demand Response - C&I	6	11	14	24	24	38	0	0	0	0	0	0
Electric Heat Initiative	0	0	0	0	0	0	0	0	0	0	0	0
Electric Vehicle Initiative	0	0	0	0	0	0	0	0	0	0	0	0
Behind-the-Meter Storage	0	1	1	2	1	2	0	0	0	0	0	0
Utility-Scale Storage	3	5	5	11	8	16	0	0	0	0	0	0
Non-Wires Alternatives	3	6	6	12	9	18	0	0	0	0	0	0
Existing Energy Efficiency	0	0	0	0	0	0	0	0	0	0	0	0
PST Support Services												
Low-Income: participation in PST initiatives	0	0	0	0	0	0	0	0	0	0	0	0
Low-Income: participation in LI rate	0	0	0	0	0	0	0	0	0	0	0	0
Provision of Customer Information	0	0	0	0	0	0	0	0	0	0	0	0
Peak Demand Forecasting (one-year)	0	0	0	0	0	0	0	0	0	0	0	0
AMI Capabilities (2022)	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal New PIMs	**22**	**42**	**38**	**71**	**57**	**103**	-	-	-	-	-	-

Performance Incentive Mechanism	Energy Peak (MWh)						GHG (Tons)					
	2019	2019	2020	2020	2021	2021	2019	2019	2020	2020	2021	2021
	Medium	High	Medium	High	Medium	High	Medium	High	Medium	High	Medium	High
System Efficiency												
Transmission Peak Demand Reduction	0	0	0	0	0	0	0	0	0	0	0	0
FCM Peak Demand Reduction	15	29	15	31	16	32	0	0	0	0	0	0
Distributed Energy Resources												
Demand Response - Residential	1	2	3	5	6	9	0	0	0	0	0	0
Demand Response - C&I	8	14	18	30	30	48	0	0	0	0	0	0
Electric Heat Initiative	0	0	0	0	0	0	0	0	0	0	0	0
Electric Vehicle Initiative	0	0	0	0	0	0	557	1,114	1,314	2,625	2,339	4,676
Behind-the-Meter Storage	1	2	2	4	3	6	0	0	0	0	0	0
Utility-Scale Storage	3	6	6	12	9	18	0	0	0	0	0	0
Non-Wires Alternatives	0	0	0	0	0	0	0	0	0	0	0	0
Existing Energy Efficiency	0	0	0	0	0	0	0	0	0	0	0	0
PST Support Services												
Low-Income: participation in PST initiatives	0	0	0	0	0	0	0	0	0	0	0	0
Low-Income: participation in LI rate	0	0	0	0	0	0	0	0	0	0	0	0
Provision of Customer Information	0	0	0	0	0	0	0	0	0	0	0	0
Peak Demand Forecasting (one-year)	0	0	0	0	0	0	0	0	0	0	0	0
AMI Capabilities (2022)	0	0	0	0	0	0	0	0	0	0	0	0
Subtotal New PIMs	**28**	**53**	**44**	**82**	**64**	**113**	**557**	**1,114**	**1,314**	**2,625**	**2,339**	**4,676**

INCENTIVES
Division Proposal

Performance Incentive Mechanism	Bps or Shared Savings	% to Company	Assumed Costs as % of Benefits	BCR	Target Units	Incentive for Quantified Net Benefits						Unquantified Benefits
						2019		2020		2021		
						Medium	High	Medium	High	Medium	High	
System Efficiency												
Transmission Peak Demand Reduction	bps	50%	0%		MW below baseline	40	80	46	93	51	103	
FCM Peak Demand Reduction	bps	50%	0%		MW below baseline	9	18	15	30	21	42	
Distributed Energy Resources						-	-	-	-	-	-	
Demand Response - Residential	shared savings	50%	90%	1.11	Incremental MW	0	0	0	0	0	1	R&R; Mkt Trnsf
Demand Response - C&I	shared savings	50%	70%	1.43	Incremental MW	2	3	4	7	7	11	R&R; Mkt Trnsf
Electric Heat Initiative	shared savings	50%	71%	1.40	Incremental Tonnes C	2	3	3	3	3	3	R&R; Mkt Trnsf; LI
Electric Vehicle Initiative	bps	50%	80%	1.25	Incremental Tonnes C	1	1	1	3	2	4	Mkt Trnsf
Behind-the-Meter Storage	shared savings	50%	90%	1.11	Incremental MW	0	1	1	1	1	2	R&R; Mkt Trnsf
Utility-Scale Storage	shared savings	50%	90%	1.11	Incremental MW	2	5	5	10	8	15	R&R; Mkt Trnsf
Non-Wires Alternatives	shared savings	50%	90%	1.11	Incremental MW	1	2	2	4	3	6	Mkt Trnsf
Existing Energy Efficiency		5%	33%	3.03	Incremental MW	264	264	283	283	269	269	
PST Support Services						0	0	0	0	0	0	
Low-Income: participation in PST initiatives	bps				% LI cust in initiative	0	0	0	0	0	0	LI benefits
Low-Income: participation in LI rate	bps				% LI cust in initiative	0	0	0	0	0	0	LI benefits
Provision of Customer Information	bps				0	0	0	0	0	0	0	PST Support
Peak Demand Forecasting (one-year)	bps				0	0	0	0	0	0	0	PST Support
AMI Capabilities (2022)					# cust with TVR	0	0	0	0	0	0	
Subtotal Existing PIMs						264	264	283	283	269	269	
Subtotal New PIMs						57	112	77	150	96	187	
Total PIMs						321	375	360	433	366	457	

Performance Incentive Mechanism	Additional Bps for Unquantified Benefits						Incentives (Basis Points)						Incentives ($1000)					
	2019		2020		2021		2019	2019	2020	2020	2021	2021	2019	2019	2020	2020	2021	2021
	Medium (bps)	High (bps)	Medium (bps)	High (bps)	Medium (bps)	High (bps)	Medium (bps)	High (bps)	Medium (bps)	High (bps)	Medium (bps)	High (bps)	Medium ($1,000)	High ($1,000)	Medium ($1,000)	High ($1,000)	Medium ($1,000)	High ($1,000)
System Efficiency																		
Transmission Peak Demand Reduction	-	-	-	-	-	-	40	80	46	93	51	103	$2,383	$4,765	$2,800	$5,599	$3,266	$6,531
FCM Peak Demand Reduction	-	-	-	-	-	-	9	18	15	30	21	42	$527	$1,054	$907	$1,814	$1,351	$2,702
Distributed Energy Resources	-	-	-	-	-	-	-	-	-	-	-	-	$0	$0	$0	$0	$0	$0
Demand Response - Residential	1	1	1	1	1	1	1	1	1	1	1	2	$64	$68	$74	$83	$93	$108
Demand Response - C&I	1	1	1	1	1	1	3	4	5	8	8	12	$162	$239	$306	$470	$504	$769
Electric Heat Initiative	1	2	1	2	1	2	3	5	4	5	4	5	$191	$277	$225	$318	$232	$330
Electric Vehicle Initiative	2	3	2	3	2	3	3	4	3	6	4	7	$152	$245	$199	$338	$265	$467
Behind-the-Meter Storage	1	2	1	2	1	2	1	3	2	3	2	4	$78	$157	$104	$208	$137	$273
Utility-Scale Storage	1	2	1	2	1	2	3	7	6	12	9	17	$194	$389	$358	$716	$545	$1,090
Non-Wires Alternatives	1	2	1	2	1	2	2	4	3	6	4	8	$108	$215	$167	$334	$241	$482
Existing Energy Efficiency	-	-	-	-	-	-	105	105	90	90	86	86	$6,247	$6,247	$5,455	$5,455	$5,455	$5,455
PST Support Services	-	-	-	-	-	-	-	-	-	-	-	-	$0	$0	$0	$0	$0	$0
Low-Income: participation in PST initiatives	2	3	2	3	2	3	2	3	2	3	2	3	$119	$178	$121	$182	$127	$191
Low-Income: participation in LI rate	2	3	2	3	2	3	2	3	2	3	2	3	$119	$178	$121	$182	$127	$191
Provision of Customer Information	1	-	-	-	-	-	1	#VALUE!	-	-	-	-	$59	#VALUE!	$0	$0	$0	$0
Peak Demand Forecasting (one-year)	1	-	-	-	-	-	1	#VALUE!	-	-	-	-	$59	#VALUE!	$0	$0	$0	$0
AMI Capabilities (2022)	-	-	-	-	-	-	-	-	-	-	-	-	$0	$0	$0	$0	$0	-
Subtotal Existing PIMs							105	105	90	90	86	86						
Subtotal New PIMs							71	#VALUE!	89	169	108	206	$4,216	#VALUE!	$5,382	$10,244	$6,888	$13,132
Total PIMs							176	#VALUE!	179	259	194	292						
System Efficiency							49	98	61	122	73	145						
New DERs							16	27	24	41	32	55						
Other							6	#VALUE!	4	6	4	6						

BENEFITS OF DIVISION PROPOSAL

Avoided Costs/Unit

Performance Incentive Mechanism	Assumed Measure Life (yrs)	FCM Benefits ($/MW-yr)						Transmission Peak Benefits ($/MW-yr)					
Lookup Cells		FCM	FCM	FCM	FCM	FCM	FCM	Transmissior	Transmissior	Transmissior	Transmissior	Transmissior	Transmissior
Lookup Cells		'[Division Ex	'[Division Ex	'[Division Ex	'[Division Ex	'[Division Ex	'[Division Ex	'[Division Ex	'[Division Ex	'[Division Ex	'[Division Ex	'[Division Ex	'[Division Ex
Lookup Cells		2019Mediu	2019High	2020Mediu	2020High	2021Mediu	2021High	2019Mediu	2019High	2020Mediu	2020High	2021Mediu	2021High
		2019	2019	2020	2020	2021	2021	2019	2019	2020	2020	2021	2021
		Medium	High	Medium	High	Medium	High	Medium	High	Medium	High	Medium	High
System Efficiency													
Transmission Peak Demand Reduction	3	$0	$0	$44,431	$44,431	$92,027	$92,027	$339,949	$339,949	$361,643	$361,643	$383,905	$383,905
FCM Peak Demand Reduction	3	$0	$0	$44,431	$44,431	$92,027	$92,027	$339,949	$339,949	$361,643	$361,643	$383,905	$383,905
Distributed Energy Resources													
Demand Response - Residential	1	$0	$0	$0	$0	$0	$0	$112,228	$112,228	$119,647	$119,647	$127,232	$127,232
Demand Response - C&I	1	$0	$0	$0	$0	$0	$0	$112,228	$112,228	$119,647	$119,647	$127,232	$127,232
Electric Heat Initiative	25	$779,476	$779,476	$822,347	$822,347	$867,576	$867,576	#########	#########	#########	#########	#########	#########
Electric Vehicle Initiative	10	$301,924	$301,924	$375,417	$375,417	$449,931	$449,931	#########	#########	#########	#########	#########	#########
Behind-the-Meter Storage	5	$82,682	$82,682	$132,480	$132,480	$186,397	$186,397	$570,558	$570,558	$605,655	$605,655	$641,537	$641,537
Utility-Scale Storage	5	$82,682	$82,682	$132,480	$132,480	$186,397	$186,397	$570,558	$570,558	$605,655	$605,655	$641,537	$641,537
Non-Wires Alternatives	3	$0	$0	$44,431	$44,431	$92,027	$92,027	$339,949	$339,949	$361,643	$361,643	$383,905	$383,905
Existing Energy Efficiency	12	$404,241	$404,241	$480,648	$480,648	$562,516	$562,516	#########	#########	#########	#########	#########	#########
PST Support Services													
Low-Income: participation in PST initiatives	1	$0	$0	$0	$0	$0	$0	$112,228	$112,228	$119,647	$119,647	$127,232	$127,232
Low-Income: participation in LI rate	1	$0	$0	$0	$0	$0	$0	$112,228	$112,228	$119,647	$119,647	$127,232	$127,232
Data Access	1	$0	$0	$0	$0	$0	$0	$112,228	$112,228	$119,647	$119,647	$127,232	$127,232
Peak Demand Forecasting (one-year)	1	$0	$0	$0	$0	$0	$0	$112,228	$112,228	$119,647	$119,647	$127,232	$127,232
AMI Capabilities (2022)	1	$0	$0	$0	$0	$0	$0	$112,228	$112,228	$119,647	$119,647	$127,232	$127,232

Performance Incentive Mechanism	Distribution Benefits ($/MW-yr)						Energy Peak Benefits ($/MW)					
Lookup Cells	Distribution	Distribution	Distribution	Distribution	Distribution	Distribution	Energy Peak	Energy Peak	Energy Peak	Energy Peak	Energy Peak	Energy Peak
Lookup Cells	'[Division Ex	'[Division Ex	'[Division Ex	'[Division Ex	'[Division Ex	'[Division Ex	'[Division Ex	'[Division Ex	'[Division Ex	'[Division Ex	'[Division Ex	'[Division Ex
Lookup Cells	2019Mediu	2019High	2020Mediu	2020High	2021Mediu	2021High	2019Mediu	2019High	2020Mediu	2020High	2021Mediu	2021High
	2019	2019	2020	2020	2021	2021	2019	2019	2020	2020	2021	2021
	Medium	High	Medium	High	Medium	High	Medium	High	Medium	High	Medium	High
System Efficiency												
Transmission Peak Demand Reduction	$218,354	$218,354	$219,113	$219,113	$223,419	$223,419	$200	$200	$197	$197	$193	$193
FCM Peak Demand Reduction	$218,354	$218,354	$219,113	$219,113	$223,419	$223,419	$200	$200	$197	$197	$193	$193
Distributed Energy Resources												
Demand Response - Residential	$71,876	$71,876	$76,276	$76,276	$82,563	$82,563	$72	$72	$73	$73	$66	$66
Demand Response - C&I	$71,876	$71,876	$76,276	$76,276	$82,563	$82,563	$72	$72	$73	$73	$66	$66
Electric Heat Initiative	#########	#########	#########	#########	#########	#########	$1,170	$1,170	$1,159	$1,159	$1,145	$1,145
Electric Vehicle Initiative	$639,855	$639,855	$655,520	$655,520	$683,937	$683,937	$598	$598	$617	$617	$637	$637
Behind-the-Meter Storage	$344,906	$344,906	$363,102	$363,102	$360,623	$360,623	$314	$314	$316	$316	$319	$319
Utility-Scale Storage	$344,906	$344,906	$363,102	$363,102	$360,623	$360,623	$314	$314	$316	$316	$319	$319
Non-Wires Alternatives	$218,354	$218,354	$219,113	$219,113	$223,419	$223,419	$200	$200	$197	$197	$193	$193
Existing Energy Efficiency												
PST Support Services												
Low-Income: participation in PST initiatives	$71,876	$71,876	$76,276	$76,276	$82,563	$82,563	$72	$72	$73	$73	$66	$66
Low-Income: participation in LI rate	$71,876	$71,876	$76,276	$76,276	$82,563	$82,563	$72	$72	$73	$73	$66	$66
Data Access	$71,876	$71,876	$76,276	$76,276	$82,563	$82,563	$72	$72	$73	$73	$66	$66
Peak Demand Forecasting (one-year)	$71,876	$71,876	$76,276	$76,276	$82,563	$82,563	$72	$72	$73	$73	$66	$66
AMI Capabilities (2022)	$71,876	$71,876	$76,276	$76,276	$82,563	$82,563	$72	$72	$73	$73	$66	$66

Performance Incentive Mechanism	GHG Benefits ($/MWh)						GHG ($/Tonne)						Initiative Net Benefits ($/tonne over study period)					
Lookup Cells	GHG MWh	GHG MWh	GHG MWh	GHG MWh	GHG MWh	GHG MWh	GHG tons	GHG tons	GHG tons	GHG tons	GHG tons	GHG tons						
Lookup Cells	'[Division Ex	'[Division Ex	'[Division Ex	'[Division Ex	'[Division Ex	'[Division Ex	'[Division Ex	'[Division Ex	'[Division Ex	'[Division Ex	'[Division Ex	'[Division Exhibit 4_Docket 4770.xlsx]Global Inputs'!H8						
Lookup Cells	2019Mediu	2019High	2020Mediu	2020High	2021Mediu	2021High	2019Mediu	2019High	2020Mediu	2020High	2021Mediu	2021High	2019Medium	2019High	2020Medium	2020High	2021Medium	2021High
	2019	2019	2020	2020	2021	2021	2019	2019	2020	2020	2021	2021	2019	2019	2020	2020	2021	2021
	Medium	High	Medium	High	Medium	High	Medium	High	Medium	High	Medium	High	Medium	High	Medium	High	Medium	High
System Efficiency																		
Transmission Peak Demand Reduction	$125	$125	$125	$125	$124	$124	$220	$220	$220	$220	$218	$218						
FCM Peak Demand Reduction	$125	$125	$125	$125	$124	$124	$220	$220	$220	$220	$218	$218						
Distributed Energy Resources																		
Demand Response - Residential	$44	$44	$44	$44	$44	$44	$77	$77	$78	$78	$77	$77						
Demand Response - C&I	$44	$44	$44	$44	$44	$44	$77	$77	$78	$78	$77	$77						
Electric Heat Initiative	$660	$660	$668	$668	$676	$676	$1,164	$1,164	$1,177	$1,177	$1,191	$1,191	$1,984	$1,984	$1,984	$1,984	$1,984	$1,984
Electric Vehicle Initiative	$340	$340	$338	$338	$334	$334	$600	$600	$596	$596	$590	$590						
Behind-the-Meter Storage	$196	$196	$196	$196	$194	$194	$346	$346	$345	$345	$342	$342						
Utility-Scale Storage	$196	$196	$196	$196	$194	$194	$346	$346	$345	$345	$342	$342						
Non-Wires Alternatives	$125	$125	$125	$125	$124	$124	$220	$220	$220	$220	$218	$218						
Existing Energy Efficiency																		
PST Support Services																		
Low-Income: participation in PST initiatives	$44	$44	$44	$44	$44	$44	$77	$77	$78	$78	$77	$77						
Low-Income: participation in LI rate	$44	$44	$44	$44	$44	$44	$77	$77	$78	$78	$77	$77						
Data Access	$44	$44	$44	$44	$44	$44	$77	$77	$78	$78	$77	$77						
Peak Demand Forecasting (one-year)	$44	$44	$44	$44	$44	$44	$77	$77	$78	$78	$77	$77						
AMI Capabilities (2022)	$44	$44	$44	$44	$44	$44	$77	$77	$78	$78	$77	$77						

Outcomes

Performance Incentive Mechanism	Target Units	Convert Tx Months of Savings to Years	FCM Peak Coincidence	Transmission Peak Coincidence	Distribution Peak Coincidence	FCM Savings (MW-yr)						Transmission Savings (MW-yr)					
						2019	2019	2020	2020	2021	2021	2019	2019	2020	2020	2021	2021
						Medium	High	Medium	High	Medium	High	Medium	High	Medium	High	Medium	High
System Efficiency																	
Transmission Peak Demand Reduction	MW below baseline	9%	0%	100%	5%	0	0	0	0	0	0	10	21	12	23	13	26
FCM Peak Demand Reduction	MW below baseline	100%	100%	8%	20%	15	29	15	31	16	32	1	2	1	3	1	3
Distributed Energy Resources																	
Demand Response - Residential	Incremental MW	100%	100%	25%	80%	1	2	3	5	6	9	0	1	1	1	2	2
Demand Response - C&I	Incremental MW	100%	100%	25%	80%	8	14	18	30	30	48	2	4	5	8	8	12
Electric Heat Initiative	crementaI Tonnes CO2	100%	0%	0%	0%	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Electric Vehicle Initiative	crementaI Tonnes CO2	100%	0%	0%	0%	0	0	0	0	0	0	0	0	0	0	0	0
Behind-the-Meter Storage	Incremental MW	100%	80%	30%	40%	1	2	2	3	2	5	0	1	1	1	1	2
Utility-Scale Storage	Incremental MW	100%	90%	90%	90%	3	5	5	11	8	16	3	5	5	11	8	16
Non-Wires Alternatives	Incremental MW	100%	60%	30%	100%	2	4	4	7	5	11	1	2	2	4	3	5
Existing Energy Efficiency	Incremental MW	100%				0	0	0	0	0	0	0	0	0	0	0	0
PST Support Services																	
Low-Income: participation in PST initiatives	% LI cust in initiative	100%															
Low-Income: participation in LI rate	% LI cust in initiative	100%															
Data Access		100%															
Peak Demand Forecasting (one-year)		100%															
AMI Capabilities (2022)	# cust with TVR	100%															
Subtotal Existing PIMs																	
Subtotal New PIMs																	
Total PIMs																	

Performance Incentive Mechanism	Distribution Savings (MW-yr)						Energy Peak (MWh)						GHG (MWh)						GHG (Tonnes)						Initiative (tonnes)					
	2019	2019	2020	2020	2021	2021	2019	2019	2020	2020	2021	2021	2019	2019	2020	2020	2021	2021	2019	2019	2020	2020	2021	2021	2019	2019	2020	2020	2021	2021
	Medium	High	Medium	High	Medium	High	Medium	High	Medium	High	Medium	High	Medium	High	Medium	High	Medium	High	Medium	High	Medium	High	Medium	High	Medium	High	Medium	High	Medium	High
System Efficiency																														
Transmission Peak Demand Reduction	6	11	6	13	7	14																								
FCM Peak Demand Reduction	3	6	3	6	3	6	15	29	15	31	16	32																		
Distributed Energy Resources																														
Demand Response - Residential	1	2	2	4	5	7	1	2	3	5	6	9																		
Demand Response - C&I	6	11	14	24	24	38	8	14	18	30	30	48																		
Electric Heat Initiative	0.0	0.0	0.0	0.0	0.0	0.0																			464.00	556.00	580.00	696.00	595.00	714.00
Electric Vehicle Initiative	0	0	0	0	0	0													557	1,114	1,314	2,625	2,339	4,676						
Behind-the-Meter Storage	0	1	1	2	1	2	1	2	2	4	3	6																		
Utility-Scale Storage	3	5	5	11	8	16	3	6	6	12	9	18																		
Non-Wires Alternatives	3	6	6	12	9	18																								
Existing Energy Efficiency	0	0	0	0	0	0																								
PST Support Services																														
Low-Income: participation in PST initiatives																														
Low-Income: participation in LI rate																														
Data Access																														
Peak Demand Forecasting (one-year)																														
AMI Capabilities (2022)																														
Subtotal Existing PIMs																														
Subtotal New PIMs																														
Total PIMs																														

Calculate $ Value of Outcomes

Performance Incentive Mechanism	FCM Benefits ($)						Transmission Benefits ($)						Distribution Benefits ($)					
	2019	2019	2020	2020	2021	2021	2019	2019	2020	2020	2021	2021	2019	2019	2020	2020	2021	2021
	Medium	High	Medium	High	Medium	High	Medium	High	Medium	High	Medium	High	Medium	High	Medium	High	Medium	High
System Efficiency																		
Transmission Peak Demand Reduction	0	0	0	0	0	0	3,521,349	7,042,698	4,199,652	8,399,305	4,947,561	9,895,121	1,243,998	2,487,996	1,399,469	2,798,939	1,583,613	3,167,226
FCM Peak Demand Reduction	0	0	679,796	1,359,591	1,472,432	2,944,864	413,605	827,210	461,095	922,190	511,874	1,023,747	637,595	1,275,190	670,485	1,340,969	714,939	1,429,879
Distributed Energy Resources																		
Demand Response - Residential	0	0	0	0	0	0	28,057	56,114	89,735	149,559	190,848	286,271	57,501	115,002	183,061	305,102	396,303	594,455
Demand Response - C&I	0	0	0	0	0	0	224,456	392,798	538,412	897,353	954,238	1,526,781	460,008	805,013	1,098,369	1,830,614	1,981,516	3,170,425
Electric Heat Initiative	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Electric Vehicle Initiative	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Behind-the-Meter Storage	66,146	132,291	211,967	423,935	447,354	894,708	171,167	342,335	363,393	726,786	577,383	1,154,766	137,963	275,925	290,482	580,964	432,748	865,496
Utility-Scale Storage	223,241	446,482	715,390	1,430,780	1,509,820	3,019,639	1,540,507	3,081,014	3,270,538	6,541,076	5,196,448	########	931,247	1,862,494	1,960,753	3,921,505	2,921,049	5,842,098
Non-Wires Alternatives	0	0	159,952	319,904	496,946	993,892	305,954	611,909	650,957	1,301,915	1,036,544	2,073,089	655,063	1,310,126	1,314,676	2,629,352	2,010,767	4,021,534
Existing Energy Efficiency	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PST Support Services																		
Low-Income: participation in PST initiatives																		
Low-Income: participation in LI rate																		
Data Access																		
Peak Demand Forecasting (one-year)																		
AMI Capabilities (2022)																		
Subtotal New PIMs	289387																	

Performance Incentive Mechanism	Energy Peak ($)						GHG Benefits ($)						GHG Benefits ($)						Initiative Net Benefits ($)					
	2019	2019	2020	2020	2021	2021	2019	2019	2020	2020	2021	2021	2019	2019	2020	2020	2021	2021	2019	2019	2020	2020	2021	2021
	Medium	High	Medium	High	Medium	High	Medium	High	Medium	High	Medium	High	Medium	High	Medium	High	Medium	High	Medium	High	Medium	High	Medium	High
System Efficiency																								
Transmission Peak Demand Reduction	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
FCM Peak Demand Reduction	2,927	5,853	3,014	6,028	3,085	6,169	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Distributed Energy Resources																								
Demand Response - Residential	72	143	220	366	397	595	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Demand Response - C&I	573	1,002	1,318	2,197	1,985	3,176	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Electric Heat Initiative	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	920,558	1,103,083	1,150,698	1,380,838	1,180,457	1,416,549
Electric Vehicle Initiative	0	0	0	0	0	0	0	0	0	0	0	0	334,226	668,452	782,659	1,564,038	1,379,183	2,757,099	0	0	0	0	0	0
Behind-the-Meter Storage	314	628	632	1,264	958	1,916	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Utility-Scale Storage	943	1,885	1,895	3,791	2,874	5,748	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Non-Wires Alternatives	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Existing Energy Efficiency	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
PST Support Services																								
Low-Income: participation in PST initiatives																								
Low-Income: participation in LI rate																								
Data Access																								
Peak Demand Forecasting (one-year)																								
AMI Capabilities (2022)																								
Subtotal New PIMs																								

Performance Incentive Mechanism	Benefits							
	2019	2019	2020	2020	2021	2021	2019-21 Cumulative	
	Medium	High	Medium	High	Medium	High	Medium	High
System Efficiency								
Transmission Peak Demand Reduction	$4,765,347	$9,530,693	$5,599,122	$11,198,244	$6,531,173	$13,062,347	$16,895,642	$33,791,284
FCM Peak Demand Reduction	$1,054,126	$2,108,253	$1,814,389	$3,628,778	$2,702,330	$5,404,660	$5,570,845	$11,141,691
Distributed Energy Resources								
Demand Response - Residential	$85,630	$171,259	$273,016	$455,027	$587,548	$881,322	$946,194	$1,507,608
Demand Response - C&I	$685,036	$1,198,814	$1,638,099	$2,730,164	$2,937,739	$4,700,382	$5,260,874	$8,629,360
Electric Heat Initiative	$920,558	$1,103,083	$1,150,698	$1,380,838	$1,180,457	$1,416,549	$3,251,714	$3,900,469
Electric Vehicle Initiative	$334,226	$668,452	$782,659	$1,564,038	$1,379,183	$2,757,099	$2,496,069	$4,989,590
Behind-the-Meter Storage	$375,590	$751,179	$866,474	$1,732,948	$1,458,443	$2,916,886	$2,700,507	$5,401,014
Utility-Scale Storage	$2,695,938	$5,391,876	$5,948,576	$11,897,152	$9,630,191	$19,260,381	$18,274,704	$36,549,409
Non-Wires Alternatives	$961,017	$1,922,035	$2,125,585	$4,251,170	$3,544,257	$7,088,515	$6,630,860	$13,261,720
Existing Energy Efficiency	$0	$0	$0	$0	$0	$0	$0	$0
PST Support Services								
Low-Income: participation in PST initiatives	$0	$0	$0	$0	$0	$0	$0	$0
Low-Income: participation in LI rate	$0	$0	$0	$0	$0	$0	$0	$0
Data Access	$0	$0	$0	$0	$0	$0	$0	$0
Peak Demand Forecasting (one-year)	$0	$0	$0	$0	$0	$0	$0	$0
AMI Capabilities (2022)	$0	$0	$0	$0	$0	$0	$0	$0
Subtotal New PIMs	$289,387	$0	$0	$0	$0	$0	$62,027,409	

Discount Rate	5.50%
Inflation	2.00%

EVs			
EV Avoided Emissions			
Wt Avg Tonnes/yr/vehicle	2.15		*Attachment DIV 1-1-3, Tab 5*

Exclude deadband MW in benefit calcs		% of Standard Error to exclude:	50%		
			2019	**2020**	**2021**
Transmission Deadband	**(MW)**	Standard Error from Synapse Predictions	114	128	142
FCM Deadband	**(MW)**	Standard Error for Company Predictions	14.6	15.3	16

Outcomes

			Incremental Outcomes less Deadband						**Cumulative Outcomes less Deadband**					
		Lookup Cells							*2019Medium*	*2019High*	*2020Medium*	*2020High*	*2021Medium*	*2021High*
			2019	2019	2020	2020	2021	2021	2019	2019	2020	2020	2021	2021
Performance Incentive Mechanism	**Outcome Units**	**Deadband**	Medium	High	Medium	High	Medium	High	Medium	High	Medium	High	Medium	High
System Efficiency														
Transmission Peak Demand Reduction	MW below baseline	Transmission Deadba	114	228	128	255	142	284	114	228	128	255	142	284
FCM Peak Demand Reduction	MW below baseline	FCM Deadband	15	29	15	31	16	32	15	29	15	31	16	32
Distributed Energy Resources			0	0	0	0	0	0	0	0	0	0	0	0
Demand Response - Residential	Incremental MW		1	2	2	3	3	4	1	2	3	5	6	9
Demand Response - C&I	Incremental MW		8	14	10	16	12	18	8	14	18	30	30	48
Electric Heat Initiative	Incremental Tonnes CO2		464.0	556.0	580.0	696.0	595.0	714.0	464.0	556.0	1044.0	1252.0	1639.0	1966.0
Electric Vehicle Initiative	Incremental Tonnes CO2		557	1,114	757	1,511	1,026	2,051	557	1,114	1,314	2,625	2,339	4,676
Behind-the-Meter Storage	Incremental MW		1	2	1	2	1	2	1	2	2	4	3	6
Utility-Scale Storage	Incremental MW		3	6	3	6	3	6	3	6	6	12	9	18
Non-Wires Alternatives	Incremental MW		3	6	3	6	3	6	3	6	6	12	9	18
Existing Energy Efficiency	Incremental MW		30	37	35	38	34	38	30	37	65	75	99	113
PST Support Services			0	0	0	0	0	0	0	0	0	0	0	0
Low-Income: participation in PST initiatives	% LI cust in initiative		5	10	5	10	5	10	5	10	5	10	5	10
Low-Income: participation in LI rate	% LI cust in initiative		4	8	4	8	4	8	4	8	4	8	4	8
Data Access			Plan	--	--	--	--	--	Plan	--	--	--	--	--
Peak Demand Forecasting (one-year)			Report	--	--	--	--	--	Report	--	--	--	--	--
AMI Capabilities (2022)	# cust with TVR		--	--	--	--	--	--	--	--	--	--	--	--

Peak Demand Forecast

	Units	Year	MW	Source
Peak Demand	MW	**2019**	1,691	*National Grid Forecast Attachment DIV 8-5*
		2020	1,679	*National Grid Forecast Attachment DIV 8-5*
		2021	1,672	*National Grid Forecast Attachment DIV 8-5*
		2022	1,668	*National Grid Forecast Attachment DIV 8-5*

FCM		**Source/Notes**	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
($/MW-yr)	**Ngrid BCA**	3; Attachment DIV 8-6; AESC 2015 Update - Appendi	$0	$0	$0	$151,748	$145,443	$154,497	$173,685	$193,939	$214,296	$235,795	$259,373	$290,551	$308,170	$314,333	$320,620	$327,032	$333,573	$340,244	$347,049	$353,990
	Daymark	Daymark Email Rec'd 3/16/18	$0	$0	$0	$55,042	$55,936	$62,393	$64,297	$69,950	$75,749	$84,529	$102,516	$97,070	$108,661	$111,185	$114,424	$117,749	$121,160	$124,661	$128,254	$131,940
	Ngrid EE Screening Tool																					
	Synapse/Division		$0	$0	$0	$55,042	$55,936	$62,393	$64,297	$69,950	$75,749	$84,529	$102,516	$97,070	$108,661	$111,185	$114,424	$117,749	$121,160	$124,661	$128,254	$131,940

Transmission			2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
($/MW-yr)	**Ngrid BCA**	Attachment DIV 1-36-1	$114,808	$117,104	$119,446																	
	Daymark	Daymark Email Rec'd 3/16/18	$124,913	$133,170	$141,612	$150,390	$159,312	$168,380	$177,593	$186,950	$196,453	$206,100	$215,893	$225,830	$235,913	$246,141	$256,513	$267,031	$277,693	$288,501	$299,454	$310,551
	Ngrid EE Screening Tool																					
	Synapse/Division		$124,913	$133,170	$141,612	$150,390	$159,312	$168,380	$177,593	$186,950	$196,453	$206,100	$215,893	$225,830	$235,913	$246,141	$256,513	$267,031	$277,693	$288,501	$299,454	$310,551

Distribution			2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
($/MW-yr)	**Ngrid BCA**																
	Daymark																
	Ngrid EE Screening Tool		$80,000	$84,897	$91,895	$80,001	$90,094	$103,490	$80,002	$95,610	$116,548	$80,003	$101,463	$131,253	$80,004	$107,675	$147,814
	Synapse/Division		$80,000	$84,897	$91,895	$80,001	$90,094	$103,490	$80,002	$95,610	$116,548	$80,003	$101,463	$131,253	$80,004	$107,675	$147,814

Distribution			2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048
($/MW-yr)	**Ngrid BCA**																
	Daymark																
	Ngrid EE Screening Tool		$80,005	$114,267	$166,465	$80,006	$121,262	$187,469	$80,007	$128,686	$211,123	$80,008	$136,565	$237,762	$80,009	$144,925	$267,762
	Synapse/Division		$80,005	$114,267	$166,465	$80,006	$121,262	$187,469	$80,007	$128,686	$211,123	$80,008	$136,565	$237,762	$80,009	$144,925	$267,762

Energy Avg			2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
($/MWh)	**Ngrid BCA**		$33	$37	$42	$46	$47	$51	$53	$56	$57	$57	$60	$61	$63	$65	$67
	Daymark																
	Ngrid EE Screening Tool																
	Synapse/Division		$33	$37	$42	$46	$47	$51	$53	$56	$57	$57	$60	$61	$63	$65	$67

Energy Avg			2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048
($/MWh)	**Ngrid BCA**		$69	$71	$73	$75	$78	$80	$82	$85	$87	$90	$93	$95	$98	$101	$104
	Daymark																
	Ngrid EE Screening Tool																
	Synapse/Division		$69	$71	$73	$75	$78	$80	$82	$85	$87	$90	$93	$95	$98	$101	$104

Energy Peak			2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
($/MWh)	**Ngrid BCA**																					
	Daymark	Daymark Email Rec'd 3/16/18	$80	$82	$74	$76	$77	$83	$87	$94	$96	$101	$110	$116	$121	$128	$136	$142	$151	$156	$166	$174
	Ngrid EE Screening Tool																					
	Synapse/Division		$80	$82	$74	$76	$77	$83	$87	$94	$96	$101	$110	$116	$121	$128	$136	$142	$151	$156	$166	$174

GHG MWh			2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
($/MWh)	**Ngrid BCA**		$49	$49	$49	$48	$48	$47	$47	$46	$46	$45	$45	$44	$54	$55	$56
	Daymark		na														
	Ngrid EE Screening Tool		---														
	Synapse/Division		$49	$49	$49	$48	$48	$47	$47	$46	$46	$45	$45	$44	$54	$55	$56

GHG MWh			2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048
($/MWh)	**Ngrid BCA**		$58	$59	$60	$61	$62	$63	$65	$66	$67	$69	$70	$71	$73	$74	
	Daymark																
	Ngrid EE Screening Tool																
	Synapse/Division		$58	$59	$60	$61	$62	$63	$65	$66	$67	$69	$70	$71	$73	$74	$0

GHG tons			2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
$/metric tonne	**Ngrid BCA**		$86	$86	$86	$85	$84	$84	$83	$82	$81	$80	$79	$78	$96	$98	$99
	Daymark		na														
	Ngrid EE Screening Tool		---														
	Synapse/Division		$86	$86	$86	$85	$84	$84	$83	$82	$81	$80	$79	$78	$96	$98	$99

GHG tons			2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	
$/metric tonne	**Ngrid BCA**		$101	$103	$106	$108	$110	$112	$114	$116	$119	$121	$124	$126	$128	$131	
	Daymark																
	Ngrid EE Screening Tool																
	Synapse/Division		$101	$103	$106	$108	$110	$112	$114	$116	$119	$121	$124	$126	$128	$131	

			Basis Points 2019	Basis Points 2020	Basis Points 2021
			2019	2020	2021
Basis Points	Bps	**Ngrid**	$59,493	$60,526	$63,602

Source: RIPDUC_2018_PeakLoadReduction_Summary_v1 (Received from Daymark 3/16/18)

Values calculated for 2.5% peak reduction

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
$/MW Generation Capacity	$ -	$ -	$ -	$ 55,042	$ 55,936	$ 62,393	$ 64,297	$ 69,950	$ 75,749	$ 84,529
$/MW Transmission Capacity	$ 124,913	$ 133,170	$ 141,612	$ 150,390	$ 159,312	$ 168,380	$ 177,593	$ 186,950	$ 196,453	$ 206,100
$/MWh Energy	$ 80	$ 82	$ 74	$ 76	$ 77	$ 83	$ 87	$ 94	$ 96	$ 101

	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
$/MW Generation Capacity	$ 102,516	$ 97,070	$ 108,661	$ 111,185	$ 114,424	$ 117,749	$ 121,160	$ 124,661	$ 128,254	$ 131,940
$/MW Transmission Capacity	$ 215,893	$ 225,830	$ 235,913	$ 246,141	$ 256,513	$ 267,031	$ 277,693	$ 288,501	$ 299,454	$ 310,551
$/MWh Energy	$ 110	$ 116	$ 121	$ 128	$ 136	$ 142	$ 151	$ 156	$ 166	$ 174

Source: Attachment DIV-1-1-3

Rhode Island Power Sector Transformation | Benefit-Cost Analysis (BCA) Models | Inputs - General

General assumptions applied to investment categories

Inputs - General

Return to Contents

General Assumptions

Assumption	Value	Unit	Source
Line Losses	8.0%	%	AESC 2015, p. 286: ISO Distribution Losses
Wholesale Risk Premium (WRP)	9.0%	%	AESC 2015, Appendix B
Distribution Losses	8.0%	%	AESC 2015, Appendix B
Real Discount Rate	1.4%	%	AESC 2015, Appendix B
Percent of Capacity Bid into FCM (%Bid)	75.0%	%	AESC 2015, Appendix B
After-tax WACC	7.5%	%	See email from Josh Nowak
Inflation Rate	2.0%	%	

Emissions Assumptions

Assumption	Value	Unit	Source	Comments
CO2 Grid Emissions Factors	1029	lbs / MWh	http://www.neep.org/sites/default/files/Emission_Factors_Attm	1 short ton = 1 US ton = 2,000 lbs
SO2 Grid Emissions Factor	0.17	lbs / MWh	http://www.neep.org/sites/default/files/Emission_Factors_Attm	1 short ton = 1 US ton = 2,000 lbs
NOX Grid Emissions Factor	0.35	lbs / MWh	http://www.neep.org/sites/default/files/Emission_Factors_Attm	1 short ton = 1 US ton = 2,000 lbs
NE-ISO Off-Peak LMU Marginal CO2 Emission rate	832	lbs / MWh	2015 ISO New England Electric Generator Air Emissions Report, Table 5.5. https://www.iso-ne.com/static-assets/docume	
NE-ISO On-Peak LMU Marginal CO2 Emission rate	891	lbs / MWh	2015 ISO New England Electric Generator Air Emissions Report, Table 5.5. https://www.iso-ne.com/static-assets/docume	

Unit Conversions

Assumption	Value	Unit	Source
Pounds to Tons conversion	0.0005	#	Standard value
kg to pounds conversion	2.2046		
kWh to MWh conversion	1000		

Time Assumptions

Assumption	Unit	Source	Comments	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
CO2 Abatement Cost	$ / short ton	2015 AESC Exhibit 4-7	AESC duration terminated at 2030. Kept same value through 2045	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
Embedded Cost in Electric Energy Market Prices	$ / short ton	2015 AESC Exhibit 4-7	AESC duration terminated at 2030. Projected linear trend through 2045	8.47	9.32	10.16	12.54	14.92	17.30	19.67	22.05	24.43	26.80	29.18	31.56	33.94	20.11	20.12
Non-embedded CO2 Costs (pre-inflation)	$ / short ton	2015 AESC Exhibit 4-7		91.53	90.68	89.84	87.46	85.08	82.70	80.33	77.95	75.57	73.20	70.82	68.44	66.06	79.89	79.88
Non-embedded CO2 Costs (post-inflation)	$ / short ton	2015 AESC Exhibit 4-7		93.36	94.34	95.34	94.67	93.94	93.13	92.27	91.33	90.31	89.23	88.06	86.80	85.46	105.41	107.51
Non-embedded CO2 Costs (pre-inflation)	$ / MWh	Calculated		47.09	46.65	46.22	45.00	43.77	42.55	41.33	40.11	38.88	37.66	36.44	35.21	33.99	41.10	41.10
Non-embedded CO2 Costs (post-inflation)	$ / MWh	Calculated		48.03	48.54	49.05	48.71	48.33	47.92	47.47	46.99	46.47	45.91	45.30	44.66	43.97	54.23	55.31

Assumption	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
CO2 Abatement Cost	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
Embedded Cost in Electric Energy Market Prices	20.13	20.14	20.15	20.16	20.17	20.18	20.19	20.20	20.21	20.22	20.23	20.24	20.25	20.26	20.27
Non-embedded CO2 Costs (pre-inflation)	79.87	79.86	79.85	79.84	79.83	79.82	79.81	79.80	79.79	79.78	79.77	79.76	79.75	79.74	79.73
Non-embedded CO2 Costs (post-inflation)	109.64	111.82	114.04	116.31	118.62	120.98	123.38	125.84	128.34	130.89	133.49	136.14	138.85	141.61	144.42
Non-embedded CO2 Costs (pre-inflation)	41.09	41.09	41.08	41.08	41.07	41.07	41.06	41.06	41.05	41.05	41.04	41.04	41.03	41.03	41.02
Non-embedded CO2 Costs (post-inflation)	56.41	57.53	58.68	59.84	61.03	62.24	63.48	64.74	66.03	67.34	68.68	70.05	71.44	72.86	74.30

SO2 & NOx Emissions Factors - non-electric fuels

Fuel	Physical Units					Conversion Factors		Short Tons/MMBTU			Source
	Reported Unit	SO2 Constant	S value	SO2	NOx	MMBTU	Short Tons	SO2	NOx	lbs/MMBTU	
Natural Gas	lb/million cuft	0.6	2000	0.6	94	1032	2000	2.907E-07	4.55426E-05	0.000581395	EPA
Propane	lb/thousand gallons	0.1	0.54	0.054	13	91.333	2000	2.9562E-07	7.11681E-05	0.000591243	https://www
Fuel Oil	lb/thousand gallons	142	0.003	42.6	18	138.5	2000	0.00015379	6.49819E-05	0.307581227	https://www

SO2 and NOX - AESC 2015 Update

Source: AESC 2015 Exhibit 4.1. Emission Allowance Prices per Short Ton. AESC notes pulled from SNL Financial.

Year	NOX 2015$	NOX 2017$	SO2 2015$	SO2 2017$
2015	10	10	1.11	1.11
2016	10	10.2	1.11	1.1322
2017	10	10.404	1.11	1.154844
2018	10	10.61208	1.11	1.17794088
2019	10	10.8243216	1.11	1.201499698
2020	10	11.04080803	1.11	1.225529692
2021	10	11.26162419	1.11	1.250040285
2022	10	11.48685668	1.11	1.275041091
2023	10	11.71659381	1.11	1.300541913
2024	10	11.95092569	1.11	1.326552751
2025	10	12.1899442	1.11	1.353083806
2026	10	12.43374308	1.11	1.380145482
2027	10	12.68241795	1.11	1.407748392
2028	10	12.9360663	1.11	1.43590336
2029	10	13.19478763	1.11	1.464621427
2030	10	13.45868338	1.11	1.493913856
2031	10	13.72785705	1.11	1.523792133
2032	10	14.00241419	1.11	1.554267975
2033	10	14.28246248	1.11	1.585353335
2034	10	14.56811173	1.11	1.617060402
2035	10	14.85947396	1.11	1.64940161
2036	10	15.15666344	1.11	1.682389642
2037	10	15.45979671	1.11	1.716037435
2038	10	15.76899264	1.11	1.750358183
2039	10	16.08437249	1.11	1.785365347
2040	10	16.40605994	1.11	1.821072654
2041	10	16.73418114	1.11	1.857494107
2042	10	17.06886477	1.11	1.894643989
2043	10	17.41024206	1.11	1.932536869
2044	10	17.7584469	1.11	1.971187606
2045	10	18.11361584	1.11	2.010611358
2046	10	18.47588816	1.11	2.050823586
2047	10	18.84540592	1.11	2.091840057

NOX & SO2 Costs (pre-inflation)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
NOX Cost	10.61208	10.8243216	11.04080803	11.26162419	11.4868567	11.7165938	11.9509257	12.1899442	12.4337431	12.6824179	12.9360663	13.1947876	13.4586834	13.7278571	14.0024142
SO2 Cost	1.17794088	1.2014997	1.225529692	1.250040285	1.27504109	1.30054191	1.32655275	1.35308381	1.38014548	1.40774839	1.43590336	1.46462143	1.49391386	1.52379213	1.55426798

	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
NOX Cost	14.2824625	14.5681117	14.859474	15.1566634	15.4597967	15.7689926	16.0843725	16.4060599	16.7341811	17.0688648	17.4102421	17.7584469	18.1136158	18.4758882	18.84541
SO2 Cost	1.58535333	1.6170604	1.64940161	1.68238964	1.71603743	1.75035818	1.78536535	1.82107265	1.85749411	1.89464399	1.93253687	1.97118761	2.01061136	2.05082359	2.09184

NOX & SO2 Costs (post-inflation)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
NOX Cost	10.8243216	11.2616242	11.7165938	12.1899442	12.6824179	13.1947876	13.7278571	14.2824625	14.859474	15.4597967	16.0843725	16.7341811	17.4102421	18.1136158	18.8454059
SO2 Cost	1.201499698	1.25004029	1.300541913	1.353083806	1.40774839	1.46462143	1.52379213	1.58535333	1.64940161	1.71603743	1.78536535	1.85749411	1.93253687	2.01061136	2.09184006

	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
NOX Cost	19.6067603	20.3988734	21.2229879	22.0803966	22.9724447	23.9005314	24.8661129	25.8707039	26.9158803	28.0032819	29.1346144	30.3116529	31.5362436	32.8103079	34.13584
SO2 Cost	2.1763504	2.26427495	2.35575166	2.45092403	2.54994136	2.65295899	2.76013853	2.87164813	2.98766271	3.10836429	3.2339422	3.36459347	3.50052304	3.64194418	3.789079

Avoided Unit Cost of Electric Capacity

Source: AESC 2015 Update, Appendix B

Period	Unit	Value	Source
2018	$/kW-yr	0	AESC 2015 Update-Appendix B
2019	$/kW-yr	0	AESC 2015 Update-Appendix B
2020	$/kW-yr	0	AESC 2015 Update-Appendix B
2021	$/kW-yr	0	AESC 2015 Update-Appendix B
2022	$/kW-yr	137.4430625	AESC 2015 Update-Appendix B
2023	$/kW-yr	129.149657	AESC 2015 Update-Appendix B
2024	$/kW-yr	134.4992808	AESC 2015 Update-Appendix B
2025	$/kW-yr	148.2384617	AESC 2015 Update-Appendix B
2026	$/kW-yr	162.2792734	AESC 2015 Update-Appendix B
2027	$/kW-yr	175.7974832	AESC 2015 Update-Appendix B
2028	$/kW-yr	189.6410963	AESC 2015 Update-Appendix B
2029	$/kW-yr	204.5142091	AESC 2015 Update-Appendix B
2030	$/kW-yr	224.6053249	AESC 2015 Update-Appendix B
2031	$/kW-yr	233.5542486	AESC 2015 Update-Appendix B
2032	$/kW-yr	233.5542486	AESC 2015 Update-Appendix B
2033	$/kW-yr	233.5542486	AESC 2015 Update-Appendix B
2034	$/kW-yr	233.5542486	AESC 2015 Update-Appendix B
2035	$/kW-yr	233.5542486	AESC 2015 Update-Appendix B
2036	$/kW-yr	233.5542486	AESC 2015 Update-Appendix B
2037	$/kW-yr	233.5542486	AESC 2015 Update-Appendix B
2038	$/kW-yr	233.5542486	AESC 2015 Update-Appendix B
2039	$/kW-yr	233.5542486	AESC 2015 Update-Appendix B
2040	$/kW-yr	233.5542486	AESC 2015 Update-Appendix B
2041	$/kW-yr	233.5542486	AESC 2015 Update-Appendix B
2042	$/kW-yr	233.5542486	AESC 2015 Update-Appendix B
2043	$/kW-yr	233.5542486	AESC 2015 Update-Appendix B
2044	$/kW-yr	233.5542486	AESC 2015 Update-Appendix B
2045	$/kW-yr	233.5542486	AESC 2015 Update-Appendix B
2046	$/kW-yr	233.5542486	AESC 2015 Update-Appendix B
2047	$/kW-yr	233.5542486	AESC 2015 Update-Appendix B

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Avoided Capacity Cost	-	-	-	-	137.44	129.15	134.50	148.24	162.28	175.80	189.64	204.51	224.61	233.55	233.55
Inflation	2%														
Conversion to MW	1000														
Avoided Capacity Cost	-	-	-	-	151,748.25	145,443.49	#######	#######	#######	#######	#######	#######	#######	#######	#######

	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
Avoided Capacity Cost	233.55	233.55	233.55	233.55	233.55	233.55	233.55	233.55	233.55	233.55	233.55	233.55	233.55	233.55	233.55
Avoided Capacity Cost	#######	#######	#######	#######	#######	#######	#######	#######	#######	#######	#######	#######	#######	#######	#######

Avoided Unit Cost of Energy

Source: AESC 2015 Update, Appendix B

Period	Units	Winter Peak	Winter Off Peak	Summer Peak	Summer Off Peak	Electric Heat Weighted Avg.	Simple Average	$/MWh	Year
2018	$/kWh	0.042948462	0.036876354	0.028704835	0.02178498	0.032578658	0.032578658	32.58	2018
2019	$/kWh	0.046553286	0.04066292	0.033877957	0.026867315	0.03699037	0.03699037	36.99	2019
2020	$/kWh	0.050901503	0.043353232	0.042024216	0.030786197	0.041766287	0.041766287	41.77	2020
2021	$/kWh	0.055575249	0.047862525	0.044949693	0.034145396	0.045633216	0.045633216	45.63	2021
2022	$/kWh	0.056916434	0.048943738	0.046748022	0.03582828	0.047109119	0.047109119	47.11	2022

2023	$/kWh	0.060706346	0.052195695	0.050601754	0.039739327	0.050810781	0.050810781	50.81	2023
2024	$/kWh	0.063356121	0.054474697	0.053075039	0.043059944	0.05349145	0.05349145	53.49	2024
2025	$/kWh	0.065459372	0.056791445	0.057419018	0.045059684	0.05618238	0.05618238	56.18	2025
2026	$/kWh	0.065377361	0.056618223	0.058916675	0.045774345	0.056671651	0.056671651	56.67	2026
2027	$/kWh	0.066370041	0.057470526	0.059460932	0.04649156	0.057448265	0.057448265	57.45	2027
2028	$/kWh	0.067678713	0.058651355	0.063320806	0.048644215	0.059573772	0.059573772	59.57	2028
2029	$/kWh	0.069197745	0.060328826	0.065926997	0.050250116	0.061425921	0.061425921	61.43	2029
2030	$/kWh	0.070740047	0.06252036	0.067778112	0.051705298	0.063185955	0.063185955	63.19	2030
2031	$/kWh	0.071133805	0.063467611	0.073302463	0.05315417	0.065264512	0.065264512	65.26	2031
2032	$/kWh	0.07234454l	0.064933877	0.076576345	0.05476718	0.067155486	0.067155486	67.16	2032
2033	$/kWh	0.073575886	0.066434018	0.079996448	0.056429138	0.069108872	0.069108872	69.11	2033
2034	$/kWh	0.074828188	0.067968815	0.083569301	0.05814153	0.071126959	0.071126959	71.13	2034
2035	$/kWh	0.076101805	0.069539071	0.087301728	0.059905886	0.073212123	0.073212123	73.21	2035
2036	$/kWh	0.0773971	0.071145603	0.091200854	0.061723783	0.075366835	0.075366835	75.37	2036
2037	$/kWh	0.078714442	0.07278925 l	0.095274126	0.063596846	0.077593666	0.077593666	77.59	2037
2038	$/kWh	0.080054206	0.074470871	0.099529321	0.065526748	0.079895286	0.079895286	79.90	2038
2039	$/kWh	0.081416773	0.076191341	0.103974564	0.067515215	0.082274473	0.082274473	82.27	2039
2040	$/kWh	0.082802531	0.077951558	0.108618344	0.069564024	0.084734114	0.084734114	84.73	2040
2041	$/kWh	0.084211876	0.079752441	0.113469527	0.071675006	0.087277212	0.087277212	87.28	2041
2042	$/kWh	0.085645209	0.081594929	0.118537377	0.073850047	0.08990689	0.08990689	89.91	2042
2043	$/kWh	0.087102938	0.083479983	0.12383157	0.076091092	0.092626396	0.092626396	92.63	2043
2044	$/kWh	0.088585479	0.085408586	0.129362216	0.078400143	0.095439106	0.095439106	95.44	2044
2045	$/kWh	0.090093253	0.087381746	0.135139876	0.080779265	0.098348535	0.098348535	98.35	2045
2046	$/kWh	0.09162669	0.08940049	0.141175581	0.083230583	0.101358336	0.101358336	101.36	2046
2047	$/kWh	0.093186227	0.091465873	0.147480857	0.085756288	0.104472311	0.104472311	104.47	2047

Avoided Energy Costs Electric Heat and Electric Vehicles Weighted Average

Seasonal Avoided Energy Costs (pre-inflation)

Period	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Winter On-Peak	0.042948462	0.046553286	0.050901503	0.055575249	0.056916434	0.060706346	0.063356121	0.06545937	0.065377361	0.066370041	0.06767871	0.06919774	0.07074005	0.0711338	0.07234454
Winter Off-Peak	0.036876354	0.04066292	0.043353232	0.047862525	0.048943738	0.052195695	0.054474697	0.05679145	0.056618223	0.057470526	0.05865135	0.06032883	0.06252036	0.06346761	0.06493388
Summer On-Peak	0.028704835	0.033877957	0.042024216	0.044949693	0.046748022	0.050601754	0.053075039	0.05741902	0.058916675	0.059460932	0.06332081	0.065927	0.06777811	0.07330246	0.07657635
Summer Off-Peak	0.02178498	0.026867315	0.030786197	0.034145396	0.03582828	0.039739327	0.043059944	0.04505968	0.045774345	0.04649156	0.04864421	0.05025012	0.0517053	0.05315417	0.05476718

Period	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
Winter On-Peak	0.07357589	0.07482819	0.07610181	0.0773971	0.07871444	0.08005421	0.08141677	0.08280253	0.08421188	0.08564521	0.08710294	0.08858548	0.09009325	0.09162669	0.09318623
Winter Off-Peak	0.06643402	0.06796882	0.06953907	0.0711456	0.07278925	0.07447087	0.07619134	0.07795156	0.07975244	0.08159493	0.08347998	0.08540859	0.08738175	0.08940049	0.09146587
Summer On-Peak	0.07999645	0.0835693	0.08730173	0.09120085	0.09527413	0.09952932	0.10397456	0.10861834	0.11346953	0.11853738	0.12383157	0.12936222	0.13513988	0.14117558	0.14748086
Summer Off-Peak	0.05642914	0.05814153	0.05990589	0.06172378	0.06359685	0.06552675	0.06751522	0.06956402	0.07167501	0.07385005	0.07609109	0.07840014	0.08077926	0.08323058	0.08575629

Seasonal and Peak Segmentation

Winter months / year	8
Summer months / year	4
Hours / year	8760
On-peak hours / day	16
Off-peak hours / day	8

Season	On-Peak	Off-Peak	Total
Winter	3,893.33	1,946.67	5,840.00
Summer	1,946.67	973.33	2,920.00

Electric Heat & EV Seasonal Load Segmentation

Season	Ratio
Summer Off-Peak	11.11%
Summer On-Peak	22.22%
Winter Off-Peak	22.22%
Winter On-Peak	44.44%
	100.00%

Weighted Average Annual Price (pre-inflation & WRP)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Hourly Wght. Avg. YOY	0.0361	0.0402	0.0450	0.0491	0.0505	0.0542	0.0568	0.0595	0.0598	0.0606	0.0626	0.0644	0.0661	0.0679	0.0697

	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
Hourly Wght. Avg. YOY	0.0715	0.0734	0.0753	0.0773	0.0794	0.0815	0.0837	0.0860	0.0883	0.0907	0.0932	0.0958	0.0985	0.1012	0.1040

Add MRP & Inflation

MRP	1.09
Inflation	0.02

Weighted Average Annual Price (pre-inflation & WRP)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Hourly Wght. Avg. YOY	0.0401	0.0456	0.0521	0.0580	0.0608	0.0666	0.0712	0.0760	0.0779	0.0806	0.0848	0.0890	0.0933	0.0977	0.1022

	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
Hourly Wght. Avg. YOY	0.1070	0.1120	0.1173	0.1228	0.1286	0.1347	0.1411	0.1478	0.1549	0.1623	0.1701	0.1783	0.1869	0.1959	0.2054

Avoided REC Cost

Source: AESC 2015 Update, Appendix B

Period	Units	Value
2018	$/kWh	0.005508139
2019	$/kWh	0.005958249
2020	$/kWh	0.005659665
2021	$/kWh	0.00680032
2022	$/kWh	0.006509963
2023	$/kWh	0.006051674
2024	$/kWh	0.005772086
2025	$/kWh	0.005405181
2026	$/kWh	0.004985127
2027	$/kWh	0.004586611
2028	$/kWh	0.004206788
2029	$/kWh	0.004558828
2030	$/kWh	0.004253013
2031	$/kWh	0.004253013
2032	$/kWh	0.004253013
2033	$/kWh	0.004253013
2034	$/kWh	0.004253013
2035	$/kWh	0.004253013
2036	$/kWh	0.004253013
2037	$/kWh	0.004253013
2038	$/kWh	0.004253013
2039	$/kWh	0.004253013
2040	$/kWh	0.004253013
2041	$/kWh	0.004253013
2042	$/kWh	0.004253013
2043	$/kWh	0.004253013
2044	$/kWh	0.004253013
2045	$/kWh	0.004253013
2046	$/kWh	0.004253013
2047	$/kWh	0.004253013

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Avoided Capacity Cost (pre	0.0055	0.0060	0.0057	0.0068	0.0065	0.0061	0.0058	0.0054	0.0050	0.0046	0.0042	0.0046	0.0043	0.0043	0.0043
Avoided Capacity Cost (pos	6.12	6.76	6.55	8.02	7.83	7.43	7.23	6.90	6.49	6.09	5.70	6.30	6.00	6.12	6.24

	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
Avoided Capacity Cost (pre	0.0043	0.0043	0.0043	0.0043	0.0043	0.0043	0.0043	0.0043	0.0043	0.0043	0.0043	0.0043	0.0043	0.0043	0.0043
Avoided Capacity Cost (pos	6.36	6.49	6.62	6.75	6.89	7.03	7.17	7.31	7.46	7.61	7.76	7.91	8.07	8.23	8.40

MRP	1.09
Inflation	2%
Convert to MW	1,000.00

DRIPE

Source: AESC 2015 Update, Appendix B

Energy

Period	Unit	Winter Peak	Winter Off Peak	Summer Peak	Summer Off Peak	Electric Heat -Wgt. Avg.	Seasonal Weighted Average	Energy Storage - Wgt. Avg.
2018	$/kWh	1.25566E-06	5.06517E-07	0	0	4.40545E-07	7.3969E-07	8.12081E-07
2019	$/kWh	0	0	0	0	0	0	0
2020	$/kWh	0	0	0	0	0	0	0

Capacity

Period	Unit	Winter	Summer	ric Heat - Weighted Ave	Solar - Seasonal Weighted Average	Energy Storage - Wgt. Avg.
2018	$/kWh	0.001583956	0.00103838	0.001311168	0.00136285	0.001402097
2019	$/kWh	0.001012791	0.00068337	0.00084808	0.000879286	0.000902984
2020	$/kWh	0.000991781	0.000669757	0.000830769	0.000861274	0.00088444
2021	$/kWh	0.000179686	0.000165304	0.000172495	0.000173857	0.000174892
2022	$/kWh	0.000179201	0.000164577	0.000171889	0.000173274	0.000174326
2023	$/kWh	0.000178737	0.000163881	0.000171309	0.000172717	0.000173785
2024	$/kWh	0.000178182	0.000163048	0.000170615	0.000172049	0.000173137
2025	$/kWh	0.00017763	0.000162221	0.000169925	0.000171385	0.000172494
2026	$/kWh	0.000177082	0.000161399	0.000169241	0.000170726	0.000171855
2027	$/kWh	0.000176538	0.000160583	0.00016856	0.000170072	0.00017122
2028	$/kWh	0.000175998	0.000159772	0.000167885	0.000169422	0.000170589
2029	$/kWh	0.000175461	0.000158967	0.000167214	0.000168776	0.000169963
2030	$/kWh	0.000174928	0.000158167	0.000166548	0.000168135	0.000169341
2031	$/kWh	0.000174928	0.000158167	0.000166548	0.000168135	0.000169341
2032	$/kWh	0.000174928	0.000158167	0.000166548	0.000168135	0.000169341
2033	$/kWh	0.000174928	0.000158167	0.000166548	0.000168135	0.000169341
2034	$/kWh	0.000174928	0.000158167	0.000166548	0.000168135	0.000169341
2035	$/kWh	0.000174928	0.000158167	0.000166548	0.000168135	0.000169341
2036	$/kWh	0.000174928	0.000158167	0.000166548	0.000168135	0.000169341
2037	$/kWh	0.000174928	0.000158167	0.000166548	0.000168135	0.000169341
2038	$/kWh	0.000174928	0.000158167	0.000166548	0.000168135	0.000169341
2039	$/kWh	0.000174928	0.000158167	0.000166548	0.000168135	0.000169341
2040	$/kWh	0.000174928	0.000158167	0.000166548	0.000168135	0.000169341
2041	$/kWh	0.000174928	0.000158167	0.000166548	0.000168135	0.000169341
2042	$/kWh	0.000174928	0.000158167	0.000166548	0.000168135	0.000169341
2043	$/kWh	0.000174928	0.000158167	0.000166548	0.000168135	0.000169341
2044	$/kWh	0.000174928	0.000158167	0.000166548	0.000168135	0.000169341
2045	$/kWh	0.000174928	0.000158167	0.000166548	0.000168135	0.000169341
2046	$/kWh	0.000174928	0.000158167	0.000166548	0.000168135	0.000169341
2047	$/kWh	0.000174928	0.000158167	0.000166548	0.000168135	0.000169341

Electric Heat and Electric Vehicles - DRIPE (pre-inflation)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Energy	4.40545E-07	0	0												
Capacity	0.001311168	0.00084808	0.000830769	0.000172495	0.000171889	0.000171309	0.000170615	0.00016993	0.000169241	0.00016856	0.00016788	0.00016721	0.00016655	0.00016655	0.00016655
Total DRIPE	0.001311609	0.00084808	0.000830769	0.000172495	0.000171889	0.000171309	0.000170615	0.00016993	0.000169241	0.00016856	0.00016788	0.00016721	0.00016655	0.00016655	0.00016655

	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
Energy															
Capacity	0.00016655	0.00016655	0.00016655	0.00016655	0.00016655	0.00016655	0.00016655	0.00016655	0.00016655	0.00016655	0.00016655	0.00016655	0.00016655	0.00016655	0.00016655
Total DRIPE	0.00016655	0.00016655	0.00016655	0.00016655	0.00016655	0.00016655	0.00016655	0.00016655	0.00016655	0.00016655	0.00016655	0.00016655	0.00016655	0.00016655	0.00016655

Inflation	2%
Conversion to MW	1,000.00

Electric Heat DRIPE (post inflation)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Total DRIPE	1.337840737	0.882342644	0.881618693	0.186713876	0.189779136	0.19292199	0.195982934	0.19909469	0.202258148	0.205474195	0.20874375	0.21206773	0.2154471	0.21975604	0.22415116

	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
Total DRIPE	0.22863418	0.23320687	0.237871	0.24262842	0.24748099	0.25243061	0.25747922	0.26262881	0.26788139	0.27323901	0.27870379	0.28427787	0.28996343	0.2957627	0.30167795

Solar DRIPE

Solar DRIPE (pre-inflation)	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Energy	7.39688E-07	0	0							
Capacity	0.00136285	0.000879286	0.000861274	0.000173857	0.000173274	0.000172717	0.000172049	0.00017139	0.000170726	0.000170072
Total DRIPE	0.00136359	0.000879286	0.000861274	0.000173857	0.000173274	0.000172717	0.000172049	0.00017139	0.000170726	0.000170072

Solar DRIPE (pre-inflation)	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Energy										
Capacity	0.00016942	0.00016878	0.00016814	0.00016814	0.00016814	0.00016814	0.00016814	0.00016814	0.00016814	0.00016814
Total DRIPE	0.00016942	0.00016878	0.00016814	0.00016814	0.00016814	0.00016814	0.00016814	0.00016814	0.00016814	0.00016814

Solar DRIPE (pre-inflation)	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
Energy										
Capacity	0.00016814	0.00016814	0.00016814	0.00016814	0.00016814	0.00016814	0.00016814	0.00016814	0.00016814	0.00016814
Total DRIPE	0.00016814	0.00016814	0.00016814	0.00016814	0.00016814	0.00016814	0.00016814	0.00016814	0.00016814	0.00016814

Inflation	2%
Conversion to MW	1,000.00

Solar DRIPE (post-inflation)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Total DRIPE	1.39086186	0.914809363	0.913991069	0.188188586	0.19130869	0.194506868	0.197629728	0.20080504	0.20403371	0.207316685

	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Total DRIPE	0.21065491	0.21404936	0.21750102	0.22185104	0.22628807	0.23081383	0.2354301	0.24013871	0.24494148	0.24984031

	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
Total DRIPE	0.25483712	0.25993386	0.26513254	0.27043519	0.27584389	0.28136077	0.28698798	0.29272774	0.2985823	0.30455394

Solar - Seasonal Demand by System Type

Season	Sum of 250 kW System - Annual Output (MW)	Sum of 500 kW System - Annual Output (MW)	Sum of 1,500 kW System - Annual Output (MW)
Summer Off-Peak	1%	1%	1%
Summer On-Peak	39%	39%	39%
Winter Off-Peak	1%	1%	1%
Winter On-Peak	59%	59%	59%
Total	**1**	**1**	**1**

Energy Storage DRIPE (pre-inflation)

Energy Storage DRIPE (pre-inflation)	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Energy	8.12081E-07	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Capacity	0.001402097	0.000902984	0.00088444	0.000174892	0.000174326	0.000173785	0.000173137	0.00017249	0.000171855	0.00017122	0.00017059	0.00016996	0.00016934	0.00016934	0.00016934
Total DRIPE	0.001402909	0.000902984	0.00088444	0.000174892	0.000174326	0.000173785	0.000173137	0.00017249	0.000171855	0.00017122	0.00017059	0.00016996	0.00016934	0.00016934	0.00016934

Energy Storage DRIPE (pre-inflation)	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
Energy	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Capacity	0.00016934	0.00016934	0.00016934	0.00016934	0.00016934	0.00016934	0.00016934	0.00016934	0.00016934	0.00016934	0.00016934	0.00016934	0.00016934	0.00016934	0.00016934
Total DRIPE	0.00016934	0.00016934	0.00016934	0.00016934	0.00016934	0.00016934	0.00016934	0.00016934	0.00016934	0.00016934	0.00016934	0.00016934	0.00016934	0.00016934	0.00016934

Inflation	2.00%
Convert to MWh	1,000.00

Energy Storage DRIPE (post-inflation)	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Total	1.430967683	0.939464253	0.938574317	0.189308465	0.192470217	0.195710408	0.198880287	0.20210385	0.205382054	0.208715853	0.21210623	0.2155542	0.21906076	0.22344197	0.22791081

Energy Storage DRIPE (post-inflation)	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047
Total	0.23246903	0.23711841	0.24186077	0.24669799	0.25163195	0.25666459	0.26179788	0.26703384	0.27237452	0.2778201	0.28337845	0.28904601	0.29482693	0.30072347	0.30673794

New England Residential Energy Prices

Energy Prices Residential (Case Reference case Region New England)

https://www.eia.gov/outlooks/aeo/data/browser/#/?id=3-AEO2017&region=1-1&cases=ref2017~ref_no_cpp&start=2015&end=2050&f=A&linechart=~-

09:51:48 GMT-0400 (Eastern Daylight Time)

Source: U.S. Energy Information Administration

New England Residential Energy Prices

Year	Propane 2016 $/MMBtu	Distillate Fuel Oil 2016 $/MMBtu	Natural Gas 2016 $/MMBtu	Electricity 2016 $/MMBtu
2015	20.059196	19.634937	12.999855	57.913372
2016	18.986731	15.391558	12.499926	52.962849
2017	19.159531	18.481035	12.559583	53.759666
2018	20.3908	20.35202	12.730404	46.24337
2019	20.428343	21.432173	12.863449	47.102016
2020	20.36684	21.913502	13.038426	45.619492
2021	20.38199	22.292168	13.248834	45.495861
2022	20.818222	22.562029	13.447027	47.376621
2023	21.09973	22.895624	13.598397	49.17429
2024	21.193447	23.217937	13.719156	50.349106
2025	21.149662	23.695726	13.810126	51.765896
2026	21.188416	24.066542	13.868716	52.806141
2027	21.388361	24.263973	13.997381	53.399616
2028	21.446894	24.305296	14.186235	53.822887
2029	21.470636	24.524441	14.388145	54.817307
2030	21.637087	24.984591	14.524349	55.649223
2031	22.067629	25.394388	14.584588	55.851391
2032	22.390608	25.889307	14.683081	55.949352
2033	22.452869	25.806747	14.751159	56.23835
2034	22.691654	26.115984	14.936297	56.59457
2035	22.800667	26.332081	15.181598	57.886639
2036	23.140226	26.861704	15.332048	58.283558
2037	23.296213	26.936857	15.496017	58.576546
2038	23.60668	27.103247	15.618446	58.816032
2039	24.046312	27.475222	15.740956	57.837711
2040	24.210247	27.673616	15.790576	59.10891
2041	24.474936	27.717131	15.916462	59.452782
2042	24.614227	27.769522	16.047209	59.981743
2043	24.814363	27.830799	16.209641	60.750565
2044	24.986708	27.928757	16.403036	61.422989
2045	25.068331	28.020597	16.601873	61.820881
2046	25.256636	28.191952	16.78653	62.281025
2047	25.456972	28.537254	16.932384	63.031494
2048	25.692049	28.555511	17.094194	63.291729
2049	25.812935	28.743196	17.232834	63.588299
2050	26.039854	29.019983	17.207699	65.033279

Spot vs. Long-term Fuel Purchases

Category	Percent of Total	Discount from Base Residential
Long-term	10%	10%
Spot Purchase	90%	0%
Total	100%	N/A
Source	http://www.treesfullofmoney.com/2017-heating-oil-price-predictions/	
Assumptions	Based on EIA forecast, assume prices are increasing and customers experience historical 5 - 15% savings from pre-buy	

Spot vs. Long-term - Natural Gas

Category	Percent of Total	Discount from Base Residential
Long-term	5%	5%
Spot Purchase	95%	0%
Total	100%	N/A

Spot vs. Long-term - Natural Gas

Category	Percent of Total	Discount from Base Residential
Long-term	0%	5%
Spot Purchase	100%	0%
Total	100%	N/A

Adjusted Residential Fuel Oil Prices Based on Pre-Buy Forecast

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base Distillate Fuel Oil	19.63	15.39	18.48	20.35	21.43	21.91	22.29	22.56	22.90	23.22	23.70	24.07	24.26	24.31	24.52	24.98	25.39	25.89
Base Distillate Fuel Oil - Convert $ / MMBTU to $ / Gallon	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!
Distillate Fuel Oil - Apply Pre-buy Discount	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!
Pre-buy discount	10%																	
Distillate Fuel Oil - Convert $ / Gallon to $ / MMBTU	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!

	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Base Distillate Fuel Oil	25.81	26.12	26.33	26.86	26.94	27.10	27.48	27.67	27.72	27.77	27.83	27.93	28.02	28.19	28.54	28.56	28.74	29.02
Base Distillate Fuel Oil - Convert $ / MMBTU to $ / Gallon	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!
Distillate Fuel Oil - Apply Pre-buy Discount	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!
Distillate Fuel Oil - Convert $ / Gallon to $ / MMBTU	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!	#REF!

Adjusted Residential Natural Gas Prices Based on Pre-Buy Forecast

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base Natural Gas ($ / MMBTU)	13.00	12.50	12.56	12.73	12.86	13.04	13.25	13.45	13.60	13.72	13.81	13.87	14.00	14.19	14.39	14.52	14.58	14.68
Natural Gas - Apply Price Protection Discount	12.96735536	12.46867619	12.52818404	12.69857799	12.83129038	13.00582994	13.2157119	13.41340943	13.56440101	13.6848581	13.7756007	13.8340442	13.9623875	14.1507694	14.3521746	14.4880381	14.5481265	14.6463733
Assume pre-buy discount is 5%, with 5% of customers using																		

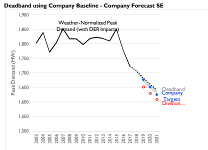
	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Base Natural Gas ($ / MMBTU)	14.75	14.94	15.18	15.33	15.50	15.62	15.74	15.79	15.92	16.05	16.21	16.40	16.60	16.79	16.93	17.09	17.23	17.21
Natural Gas - Apply Price Protection Discount	14.7142811	14.8989563	15.143644	15.2937179	15.457277	15.5793999	15.7016036	15.7510996	15.8766708	16.007091	16.1691169	16.3620284	16.5603683	16.7445637	16.890053	17.0514585	17.18975	17.165

Propane 2016 $/MMBtu

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Base Propane 2016 $/MMBtu	20.06	18.99	19.16	20.39	20.43	20.37	20.38	20.82	21.10	21.19	21.15	21.19	21.39	21.45	21.47	21.64	22.07	22.39
Propane - Apply Price Discount	20.06	18.99	19.16	20.39	20.43	20.37	20.38	20.82	21.10	21.19	21.15	21.19	21.39	21.45	21.47	21.64	22.07	22.39
Assume pre-buy discount is zero																		

	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Base Propane 2016 $/MMBtu	22.45	22.69	22.80	23.14	23.30	23.61	24.05	24.21	24.47	24.61	24.81	24.99	25.07	25.26	25.46	25.69	25.81	26.04
Propane - Apply Price Discount	22.45	22.69	22.80	23.14	23.30	23.61	24.05	24.21	24.47	24.61	24.81	24.99	25.07	25.26	25.46	25.69	25.81	26.04

Deadband using Company Baseline - Company Forecast SE



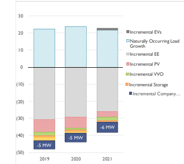
% of standard error:	Synapse Min MW Reductions	Synapse Target MW Reductions	Synapse Max MW Reductions	Synapse Med Target	Synapse Max Target	Min - MW of Benefits
	50%	100%	150.0%	100%		50%

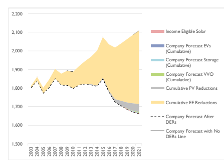
Weather-Normalized Peak Demand (with DER Impacts)

Year	Peak - Weather Norm Actual less impacts of EE and PV	Company Forecast	Company Targets (YoY Reduc)	Company Target Peak	Cumulative Reductions	Company Forecast SE	Forecast Less 0.5 SE	Synapse Min MW Reductions	Synapse Target MW Reductions	Synapse Max MW Reductions	Synapse Med Target	Synapse Max Target	Min - MW of Benefits	Med - MW of Benefits	Max - MW of Benefits
2003	1803														
2004	1839														
2005	1772														
2006	1803														
2007	1852														
2008	1817														
2009	1816														
2010	1798														
2011	1817														
2012	1822														
2013	1817														
2014	1811														
2015	1850														
2016	1778														
2017	1723	1723													
2018		1706		1706			1706								
2019		1682	-29	1677	-4.6	29.2	1667	14.6	29	44	1653	1638	0	15	29
2020		1661	-26	1651	-9.6	30.6	1646	15.3	31	46	1630	1615	0	15	31
2021		1642	-26	1625	-16.6	32.0	1626	16.0	32	48	1610	1594	0	16	32

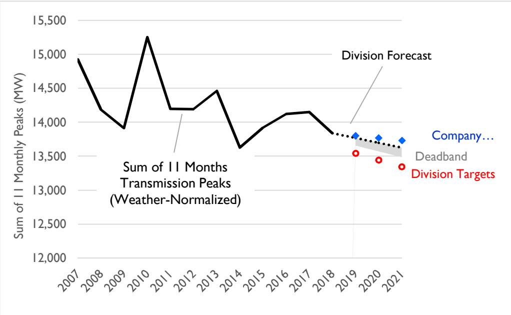
Year	Company Forecast with No DERs	Company Forecast with No DERs Line	Cumulative Load Growth	Cumulative EE Reductions	Cumulative PV Reductions	Company Forecast VVO (Cumulative)	Company Forecast Storage (Cumulative)	Company Forecast EVs (Cumulative)	Income Eligible Solar	Company Forecast After DERs	Cumulative EE Relative to 2018	Cumulative PV Relative to 2018	Cumulative Additional Company Effort	Company Target	Incremental Load Growth	Incremental EE	Incremental PV	Incremental VVO	Incremental Storage	Incremental EVs	Incremental Income Eligible Solar	Net	Incremental Company Effort
2003	1,813	1,813		(9)	0	0	0	0	0	1,803													
2004	1,860	1,860		(21)	0	0	0	0	0	1,839													
2005	1,802	1,802		(30)	0	0	0	0	0	1,772													
2006	1,844	1,844		(41)	0	0	0	0	0	1,803													
2007	1,902	1,902		(51)	0	0	0	0	0	1,852													
2008	1,878	1,878		(61)	0	0	0	0	0	1,817													
2009	1,893	1,893		(77)	0	0	0	0	0	1,816													
2010	1,887	1,887		(89)	0	0	0	0	0	1,798													
2011	1,919	1,919		(102)	(0)	0	0	0	0	1,817													
2012	1,944	1,944		(121)	(0)	0	0	0	0	1,822													
2013	1,968	1,968		(148)	(2)	0	0	0	0	1,817													
2014	2,001	2,001		(187)	(4)	0	0	0	0	1,811													
2015	2,075	2,075		(220)	(5)	0	0	0	0	1,850													
2016	2,036	2,036		(250)	(7)	0	0	0	0	1,778													
2017	2,018	2,018		(279)	(16)	0	0	0	0	1,723													
2018	2,041	2,041		(310)	(25)	0	0	0	0	1,706													
2019	2,063	2,063	22	(340)	(32)	-2	-1	0	-2	1,686	-35	-7	-5	1,681	22	(31)	(7)	(2)	(1)	0	(2)	(26)	-5
2020	2,087	2,087	46	(369)	(39)	-3	-2	0	-3	1,671	-70	-14	-10	1,661	24	(29)	(7)	(1)	(1)	0	(1)	(20)	-5
2021	2,109	2,109	68	(395)	(42)	-5	-3	1	-3	1,662	-104	-18	-16	1,646	22	(26)	(3)	(2)	(1)	1	0	(15)	-6

Notes:
Company Forecast = "Reconstituted" less EE, PV, VVO, Storage, + EVs. See Attachment DIV 8-5.
Company Forecast Standard Error: Attachment DIV 8-7-2





Actuals and Predictions



	Sum of 11 Monthly Peaks	Sum of 11 Monthly						% of standard error:	50%	100%	150%			
Year	Monthly_Peak	Weather-Norm 11 Mo Baseline	Company's YoY Target Reductions	Company's Targets	Standard _Error	Bottom of Deadband	Synapse Target	Synapse Min MW Reductions	Synapse Medium MW Reductions	Synapse High MW Reductions	Min MW for Benefits Calc (excl Deadband)	Med MW for Benefits Calc (excl Deadband)	High MW for Benefits Calc (excl Deadband)
2007	15,038	14,924											
2008	14,290	14,192											
2009	13,420	13,919											
2010	15,098	15,253											
2011	14,177	14,198											
2012	14,380	14,194											
2013	14,826	14,462											
2014	13,909	13,628											
2015	13,990	13,921											
2016	13,928	14,121											
2017	13,906	14,151											
2018	NA	13,843											
2019	NA	13,772	36	13,807	228	13,658	13,544	114	228	342	0	114	228
2020	NA	13,701	34	13,773	255	13,573	13,445	128	255	383	0	128	255
2021	NA	13,630	36	13,737	284	13,488	13,346	142	284	425	0	142	284

	Year	Monthly_Peak	HDD	Tmp_max	Tmp_min	CDD	Weather_Normalize(	Standard_Error
1	2007	15,038	238	629	447	61	14,924	
2	2008	14,290	245	598	431	45	14,192	
3	2009	13,420	224	609	455	41	13,919	
4	2010	15,098	185	718	495	76	15,253	
5	2011	14,177	234	631	433	51	14,198	
6	2012	14,380	166	685	524	55	14,194	
7	2013	14,826	239	625	448	60	14,462	
8	2014	13,909	233	618	430	42	13,628	
9	2015	13,990	250	613	418	50	13,921	
10	2016	13,928	238	612	457	57	14,121	
11	2017	13,906	247	618	436	59	14,151	
12	2018	NA	227	632	452	54	13,843	201
13	2019	NA	227	632	452	54	13,772	228
14	2020	NA	227	632	452	54	13,701	255
15	2021	NA	227	632	452	54	13,630	284
16	2022	NA	227	632	452	54	13,559	312

Source: Attachment DIV 8-4

Polk Data - National Grid

RI - Cumulative									Company Forecast					Synapse Analysis	
														2013-201	**2017-2021**
	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**		**CAGR**	**CAGR**
BEV(PEV)				32	41	117	193	313	483	725	1069	1557		77%	49%
HEV(PHEV)				178	182	413	538	772	1080	1486	2021	2726		44%	37%
				210	223	530	731	1085	1563	2211	3090	4283		51%	41%

RI - Incremental									Company Forecast					**2014-201**	**2014-202**
	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017 - Annualized**	**2018**	**2019**	**2020**	**2021**	**Std Dev**	131	359
BEV(PEV)				32	9	76	76	120	170	242	344	488			
HEV(PHEV)				178	4	231	125	234	308	406	535	705			
				210	13	307	201	354	478	648	879	1193			

Synapse Check	Forecast + .5 SD	0.5	827	1,058	1,372
	Forecast + 1 SD	1	1,007	1,238	1,552
	Forecast + 1.5 SD	1.5	1,186	1,417	1,731

Company Gross Targets	120%	778	1,055	1,432
	140%	907	1,231	1,670
	180%	1,166	1,582	2,147

Company Net Targets	Min	130	176	239
	Target	259	352	477
	Max	518	703	954

	2019		**2020**		**2021**	
	Medium	**High**	**Medium**	**High**	**Medium**	**High**
	259	518	352	703	477	954
Tons Avoided/Vehicle	2.15	2.15	2.15	2.15	2.15	2.15
Targets in Tons	556.85	1113.7	756.8	1511.45	1025.55	2051.1

Source: Attachment DIV-1-1-3, Tab "9.EH - BCA Summary"

Rhode Island Power Sector Transformation | Benefit-Cost Analysis (BCA) Models | EH - BCA Summary

EH BCA ratios, comprehensive benefits and costs, and sensitivity analyses

EH - BCA Summary

Societal Cost Test

RI Electric Heat BCA

	Electric Heat - BCA Ratio		
Benefits	Forward Commitment: Capacity Value	$	832,005
	Energy Supply & Transmission Operating Value of Energy Provided or Saved (time- and location-specific LMP)	$	(3,591,188)
	Avoided Renewable Energy Credit (REC) Cost	$	(324,190)
	Greenhouse Gas (GHG) Externality Costs	$	1,479,569
	Criteria Air Pollutant and Other Environmental Costs	$	672
	Non-Electric Avoided Fuel Cost	$	12,737,349
	Economic Development	$	-
		$	**11,134,218**
Costs	Utility / Third Party Developer Renewable Energy, Efficiency, or DER Costs	$	1,126,843
	Program Participant / Prosumer Benefits / Costs	$	6,756,766
		$	**7,883,608**

BCA Ratio		**1.41**
Net Benefits	$	3,250,610
First-Year Tonnes CO2 Avoided	$	1,638
Net Benefit/Incremental Tonne CO2	$	1,984

Comprehensive Benefits & Costs

	Applicable Cost Test			Electric Heat - BCA Ratio		
	SCT	UCT	RIM			
Benefits	x	x	x	Forward Commitment: Capacity Value	$	832,005
	x	x	x	Energy Supply & Transmission Operating Value of Energy Provided or Saved (time- and location-specific LMP)	$	(3,591,188)
	x	x	x	Avoided Renewable Energy Credit (REC) Cost	$	(324,190)
		x	x	Wholesale Market Price Impacts	$	(16,575)
	x			Greenhouse Gas (GHG) Externality Costs	$	1,479,569
	x			Criteria Air Pollutant and Other Environmental Costs	$	672
	x			Non-Electric Avoided Fuel Cost	$	12,737,349
	x			Economic Development	$	-
		x	x	Change in Utility Revenue	$	11,484,377
					$	**22,602,020**
Costs	x	x	x	Utility / Third Party Developer Renewable Energy, Efficiency, or DER Costs	$	1,126,843
	x			Program Participant / Prosumer Benefits / Costs	$	6,756,766
					$	**7,883,608**

Source: Attachment DIV 1-1-3, Tab "11.EH - Benefits"

	Forward Commitment: Capacity Value			**Yr 1**	**Yr 2**	**Yr 3**	**Yr 4**	**Yr 5**	**Yr 6**	**Yr 7**	**Yr 8**	**Yr 9**	**Yr 10**
	Reduction in Peak Load (4-yr delay)	kW	Calculated. Based on RI draft testimony.	139.21	298.16	476.84	476.84	476.84	476.84	476.84	476.84	476.84	476.84
/	1 - Losses	%	AESC 2015, p. 286. ISO Distribution Losses.	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%
=	Change in Electric Load at System	kW		151.32	324.09	518.31	518.31	518.31	518.31	518.31	518.31	518.31	518.31
x	System Coincidence Factor	%	Based on NY BCA model	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
x	Derating Factor	%	Based on NY BCA model	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00
=	Avoided Generation Capacity	kW		151.32	324.09	518.31	518.31	518.31	518.31	518.31	518.31	518.31	518.31
	Increased Energy Use	MWh		(1,473)	(3,214)	(5,103)	(5,103)	(5,103)	(5,103)	(5,103)	(5,103)	(5,103)	(5,103)
	1-Losses	%		92%	92%	92%	92%	92%	92%	92%	92%	92%	92%
	Change in Energy Use at System	MWh		-1601	-3493	-5547	-5547	-5547	-5547	-5547	-5547	-5547	-5547
	Non-Embedded CO2 Cost per MWh	$/MWh		48.03	48.54	49.05	48.71	48.33	47.92	47.47	46.99	46.47	45.91
	Electricity Added Carbon Costs			-76908	-169566	-272075	-270165	-268069	-265782	-263328	-260637	-257733	-254643
	Non-Embedded CO2 Cost per Metric Ton	$/Metric Ton		93.36	94.34	95.34	94.67	93.94	93.13	92.27	91.33	90.31	89.23
	Increase in Metric Tons of CO2	Metric Tons		(824)	(1,797)	(2,854)	(2,854)	(2,854)	(2,854)	(2,854)	(2,854)	(2,854)	(2,854)
	Fuel Oil CO2 Reduction												
	Fuel Oil CO2 Emissions Reduction	metric tons		1,287	2,841	4,492	4,492	4,492	4,492	4,492	4,492	4,492	4,492
	Net Reduction in CO2	metric tons		464	1,043	1,638	1,638	1,638	1,638	1,638	1,638	1,638	1,638
Synapse Targets:	**Incremental Reduction in CO2**	**metric tons**	**(medium target)**	**464**	**580**	**595**							
			(High Target)	**556**	**696**	**714**							

Forward Commitment: Capacity Value	**Yr 11**	**Yr 12**	**Yr 13**	**Yr 14**	**Yr 15**	**Yr 16**	**Yr 17**	**Yr 18**	**Yr 19**	**Yr 20**	**Yr 21**	**Yr 22**	**Yr 23**	**Yr 24**	**Yr 25**	**Yr 26**	**Yr 27**	**Yr 28**	**Yr 29**	**Yr 30**	
Reduction in Peak Load (4-yr delay)	476.84	476.84	476.84	476.84	476.84	402.59	317.87	222.69	222.69	222.69	222.69	222.69	222.69	222.69	222.69	157.74	83.51	-	-	-	
1 - Losses	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	
Change in Electric Load at System	518.31	518.31	518.31	518.31	518.31	437.59	345.51	242.06	242.06	242.06	242.06	242.06	242.06	242.06	242.06	171.46	90.77	-	-	-	
System Coincidence Factor	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	
Derating Factor	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	
Avoided Generation Capacity	518.31	518.31	518.31	518.31	518.31	437.59	345.51	242.06	242.06	242.06	242.06	242.06	242.06	242.06	242.06	171.46	90.77	-	-	-	
Increased Energy Use	(5,103)	(5,103)	(5,103)	(5,103)	(5,103)	(3,906)	(2,541)	(1,008)	(1,008)	(1,008)	(1,008)	(1,008)	(1,008)	(1,008)	(1,008)	(731)	(355)	-	-	-	
1-Losses	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	
Change in Energy Use at System	-5547	-5547	-5547	-5547	-5547	-4246	-2762	-1095	-1095	-1095	-1095	-1095	-1095	-1095	-1095	-795	-386	0	0	0	
Non-Embedded CO2 Cost per MWh	45.30	44.66	43.97	54.23	55.31	56.41	57.53	58.68	59.84	61.03	62.24	63.48	64.74	66.03	67.34	68.68	70.05	71.44	72.86	74.30	
Electricity Added Carbon Costs	-251291	-247703	-243871	-300822	-306800	-239527	-158919	-64264	-65541	-66844	-68172	-69527	-70908	-72318	-73755	-54583	-27061	0	0	0	
Non-Embedded CO2 Cost per Metric Ton	88.06	86.80	85.46	105.41	107.51	109.64	111.82	114.04	116.31	118.62	120.98	123.38	125.84	128.34	130.89	133.49	136.14	138.85	141.61	144.42	
Increase in Metric Tons of CO2	(2,854)	(2,854)	(2,854)	(2,854)	(2,854)	(2,185)	(1,421)	(563)	(563)	(563)	(563)	(563)	(563)	(563)	(563)	(409)	(199)	-	-	-	
Fuel Oil CO2 Reduction																					
Fuel Oil CO2 Emissions Reduction	4,492	4,492	4,492	4,492	4,492	3,593	2,567	1,414	1,414	1,414	1,414	1,414	1,414	1,414	1,414	1,026	499	-	-	-	-
Net Reduction in CO2	1,638	1,638	1,638	1,638	1,638	1,408	1,146	851	851	851	851	851	851	851	851	617	300	-	-	-	-
Incremental Reduction in CO2																					

Compare to Company Calculations

Source: Attachment DIV 1-1-3, Tab "10.EH - Inputs"			
Number of Conversions - ASHP 3 ton	39	45	50
Number of Conversions - GSHP 4 ton	18	20	24
Number of Conversions - GSHP 82 ton		1	
Source: Attachment DIV 25-18, Assumptions			
Avoided CO2 per Year/unit - ASHP 3 ton	3	3	3
Avoided CO2 per Year/unit - GSHP 4 ton	8	8	8
Avoided CO2 per Year/unit - GSHP 82 ton		59	
Source: Attachment DIV 25-18, Targets			
Incremental Avoided CO2 per Year - Equipment Incentives	171	194	224
Incremental Avoided CO2 per Year - GSHP 82 ton	-	59	-

EH - Benefits

Return to Contents

	RI Benefit Description / Calculations	Unit	SCT	UTC	RIM	Source	Yr 1	Yr 2	Yr 3	Yr 4	Yr 5	Yr 6	Yr 7	Yr 8	Yr 9	Yr 10	Yr 11	Yr 12	Yr 13	Yr 14	Yr 15	Yr 16	Yr 17	Yr 18	Yr 19	Yr 20	Yr 21	Yr 22	Yr 23	Yr 24	Yr 25	Yr 26	Yr 27	Yr 28	Yr 29	Yr 30	Nominal Value	NPV
	Forward Commitment: Capacity Value																																					
	Reduction in Peak Load (4-yr delay)	kW				Calculated. Based on RI draft testimony.	139.21	298.16	476.84	476.84	476.84	476.84	476.84	476.84	476.84	476.84	476.84	476.84	476.84	476.84	476.84	402.59	317.87	222.69	222.69	222.69	222.69	222.69	222.69	222.69	222.69	157.74	83.51	-	-	-		
/	1 - Losses	%				AESC 2015, p. 286. ISO Distribution Losses.	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%		
=	Change in Electric Load at System	kW					151.32	324.09	518.31	518.31	518.31	518.31	518.31	518.31	518.31	518.31	518.31	518.31	518.31	518.31	518.31	437.59	345.51	242.06	242.06	242.06	242.06	242.06	242.06	242.06	242.06	171.46	90.77	-	-	-	10,195.21	$4,758.02
x	System Coincidence Factor	%				Based on NY BCA model	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00		
x	Derating Factor	%				Based on NY BCA model	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00		
=	Avoided Generation Capacity	kW					151.32	324.09	518.31	518.31	518.31	518.31	518.31	518.31	518.31	518.31	518.31	518.31	518.31	518.31	518.31	437.59	345.51	242.06	242.06	242.06	242.06	242.06	242.06	242.06	242.06	171.46	90.77	-	-	-	10,195.21	4,758.02
x	Avoided Unit Cost of Electric Capacity	$ / MW				AESC 2015 Update, Appendix B	-	-	-	-	151,748.25	145,443.49	154,497.40	173,684.98	193,938.75	214,296.15	235,794.87	259,373.47	290,550.94	308,169.87	314,333.27	320,619.93	327,032.33	333,572.98	340,244.44	347,049.33	353,990.31	361,070.12	368,291.52	375,657.35	383,170.50	390,833.91	398,650.59	406,623.60	414,756.07	423,051.19		
=	**Benefit from Forward Commitment: Capacity Value**	$	x	x	x		**$ -**	**$ -**	**$ -**	**$ -**	**$ 78,653**	**$ 75,385**	**$ 80,077**	**$ 90,023**	**$ 100,520**	**$ 111,072**	**$ 122,215**	**$ 134,436**	**$ 150,595**	**$ 159,727**	**$ 162,922**	**$ 140,301**	**$ 112,993**	**$ 80,744**	**$ 82,359**	**$ 84,006**	**$ 85,686**	**$ 87,400**	**$ 89,148**	**$ 90,930**	**$ 92,749**	**$ 67,011**	**$ 36,186**	**$ -**	**$ -**	**$ -**	**$ 2,315,136**	**$ 832,005**
	Energy Supply & Transmission Operating Value of Energy Provided or Saved (time- and location-specific LMP)																																					
	Change in Energy Usage at Meter	MWh				Calculated. Based on RI draft testimony.	(1,473.03)	(3,213.87)	(5,102.95)	(5,102.95)	(5,102.95)	(5,102.95)	(5,102.95)	(5,102.95)	(5,102.95)	(5,102.95)	(5,102.95)	(5,102.95)	(5,102.95)	(5,102.95)	(5,102.95)	(3,906.37)	(2,541.26)	(1,007.61)	(1,007.61)	(1,007.61)	(1,007.61)	(1,007.61)	(1,007.61)	(1,007.61)	(1,007.61)	(731.16)	(355.43)	-	-	-		
/	1 - Losses	%				AESC 2015, p. 286. ISO Distribution Losses.	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%		
=	Change in Energy Usage at System	MWh				Calculated	(1,601.12)	(3,493.34)	(5,546.68)	(5,546.68)	(5,546.68)	(5,546.68)	(5,546.68)	(5,546.68)	(5,546.68)	(5,546.68)	(5,546.68)	(5,546.68)	(5,546.68)	(5,546.68)	(5,546.68)	(4,246.05)	(2,762.24)	(1,095.23)	(1,095.23)	(1,095.23)	(1,095.23)	(1,095.23)	(1,095.23)	(1,095.23)	(1,095.23)	(794.74)	(386.34)	-	-	-	(94,152.56)	(47,709.01)
x	Avoided Energy Cost	$ / MWh				AESC 2015 Update, Appendix B	40.12	45.63	52.07	57.95	60.82	66.58	71.17	75.96	77.92	80.58	84.83	89.02	93.26	97.68	102.23	107.00	112.02	117.28	122.80	128.60	134.69	141.08	147.80	154.86	162.27	170.07	178.25	186.86	195.91	205.42		
=	**Benefit from Energy Supply & Transmission Operating**	$	x	x	x	Calculated	**$ (64,231)**	**$ (159,415)**	**$ (288,822)**	**$ (321,447)**	**$ (337,375)**	**$ (369,301)**	**$ (394,762)**	**$ (421,338)**	**$ (432,202)**	**$ (446,972)**	**$ (470,502)**	**$ (493,756)**	**$ (517,283)**	**$ (541,781)**	**$ (567,025)**	**$ (454,343)**	**$ (309,414)**	**$ (128,446)**	**$ (134,495)**	**$ (140,846)**	**$ (147,516)**	**$ (154,520)**	**$ (161,877)**	**$ (169,607)**	**$ (177,727)**	**$ (135,158)**	**$ (68,867)**	**$ -**	**$ -**	**$ -**	**$ (8,009,028)**	**$ (3,591,188)**
	Avoided Renewable Energy Credit (REC) Cost																																					
	Change in Energy Usage at Meter	MWh				Calculated. Based on RI draft testimony.	(1,473.03)	(3,213.87)	(5,102.95)	(5,102.95)	(5,102.95)	(5,102.95)	(5,102.95)	(5,102.95)	(5,102.95)	(5,102.95)	(5,102.95)	(5,102.95)	(5,102.95)	(5,102.95)	(5,102.95)	(3,906.37)	(2,541.26)	(1,007.61)	(1,007.61)	(1,007.61)	(1,007.61)	(1,007.61)	(1,007.61)	(1,007.61)	(1,007.61)	(731.16)	(355.43)	-	-	-		
/	1 - Losses	%				AESC 2015, p. 286. ISO Distribution Losses.	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%		
=	Change in Energy Usage at System	MWh				Calculated	(1,601.12)	(3,493.34)	(5,546.68)	(5,546.68)	(5,546.68)	(5,546.68)	(5,546.68)	(5,546.68)	(5,546.68)	(5,546.68)	(5,546.68)	(5,546.68)	(5,546.68)	(5,546.68)	(5,546.68)	(4,246.05)	(2,762.24)	(1,095.23)	(1,095.23)	(1,095.23)	(1,095.23)	(1,095.23)	(1,095.23)	(1,095.23)	(1,095.23)	(794.74)	(386.34)	-	-	-	(94,152.56)	(47,709.01)
x	Avoided REC Cost	$ / MWh				AESC 2015 Update, Appendix B	6.12	6.76	6.55	8.02	7.83	7.43	7.23	6.90	6.49	6.09	5.70	6.30	6.00	6.12	6.24	6.36	6.49	6.62	6.75	6.89	7.03	7.17	7.31	7.46	7.61	7.76	7.91	8.07	8.23	8.40		
	Benefit from Avoided REC Cost	$	x	x	x	Calculated	**$ (9,805)**	**$ (23,604)**	**$ (36,312)**	**$ (44,503)**	**$ (43,455)**	**$ (41,204)**	**$ (40,086)**	**$ (38,289)**	**$ (36,019)**	**$ (33,803)**	**$ (31,624)**	**$ (34,955)**	**$ (33,263)**	**$ (33,928)**	**$ (34,607)**	**$ (27,022)**	**$ (17,930)**	**$ (7,252)**	**$ (7,397)**	**$ (7,545)**	**$ (7,695)**	**$ (7,849)**	**$ (8,006)**	**$ (8,166)**	**$ (8,330)**	**$ (6,165)**	**$ (3,057)**	**$ -**	**$ -**	**$ -**	**$ (631,871)**	**$ (324,190)**
	Wholesale Market Price Impacts																																					
	Change in Energy Usage at Meter	MWh				Calculated. Based on RI draft testimony.	(1,473.03)	(3,213.87)	(5,102.95)	(5,102.95)	(5,102.95)	(5,102.95)	(5,102.95)	(5,102.95)	(5,102.95)	(5,102.95)	(5,102.95)	(5,102.95)	(5,102.95)	(5,102.95)	(5,102.95)	(3,906.37)	(2,541.26)	(1,007.61)	(1,007.61)	(1,007.61)	(1,007.61)	(1,007.61)	(1,007.61)	(1,007.61)	(1,007.61)	(731.16)	(355.43)	-	-	-		
/	1 - Losses	%				AESC 2015, p. 286. ISO Distribution Losses.	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%	92%		
=	Change in Energy Usage at System	MWh				Calculated	(1,601.12)	(3,493.34)	(5,546.68)	(5,546.68)	(5,546.68)	(5,546.68)	(5,546.68)	(5,546.68)	(5,546.68)	(5,546.68)	(5,546.68)	(5,546.68)	(5,546.68)	(5,546.68)	(5,546.68)	(4,246.05)	(2,762.24)	(1,095.23)	(1,095.23)	(1,095.23)	(1,095.23)	(1,095.23)	(1,095.23)	(1,095.23)	(1,095.23)	(794.74)	(386.34)	-	-	-	(94,152.56)	(47,709.01)
x	DRIPE (Energy + Cross-fuel Capacity)	$ / MWh				AESC 2015 Update, Appendix B	1.34	0.88	0.88	0.19	0.19	0.19	0.20	0.20	0.20	0.21	0.21	0.21	0.22	0.22	0.22	0.23	0.23	0.24	0.24	0.25	0.25	0.26	0.26	0.27	0.27	0.28	0.28	0.29	0.30	0.30		
=	**Benefit from Wholesale Market Price Impacts**	$		x	x	Calculated	**$ (2,142)**	**$ (3,082)**	**$ (4,890)**	**$ (1,036)**	**$ (1,053)**	**$ (1,070)**	**$ (1,087)**	**$ (1,104)**	**$ (1,122)**	**$ (1,140)**	**$ (1,158)**	**$ (1,176)**	**$ (1,195)**	**$ (1,219)**	**$ (1,243)**	**$ (971)**	**$ (644)**	**$ (261)**	**$ (266)**	**$ (271)**	**$ (276)**	**$ (282)**	**$ (288)**	**$ (293)**	**$ (299)**	**$ (221)**	**$ (110)**	**$ -**	**$ -**	**$ -**	**$ (27,899)**	**$ (16,575)**

	Greenhouse Gas (GHG) Externality Costs																																			
	Change in Energy Usage at Meter	MWh		Calculated. Based on RI draft testimony.	(1,473.03)	(3,213.87)	(5,102.95)	(5,102.95)	(5,102.95)	(5,102.95)	(5,102.95)	(5,102.95)	(5,102.95)	(5,102.95)	(5,102.95)	(5,102.95)	(5,102.95)	(5,102.95)	(5,102.95)	(3,906.37)	(2,541.26)	(1,007.61)	(1,007.61)	(1,007.61)	(1,007.61)	(1,007.61)	(1,007.61)	(1,007.61)	(1,007.61)	(731.16)	(355.43)	-	-	-		
/	1 - Losses	%		AESC 2015, p. 286. ISO Distribution Losses.	92%	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92	0.92		
=	Change in Energy Usage at System	MWh		Calculated	(1,601.12)	(3,493.34)	(5,546.68)	(5,546.68)	(5,546.68)	(5,546.68)	(5,546.68)	(5,546.68)	(5,546.68)	(5,546.68)	(5,546.68)	(5,546.68)	(5,546.68)	(5,546.68)	(5,546.68)	(4,246.05)	(2,762.24)	(1,095.23)	(1,095.23)	(1,095.23)	(1,095.23)	(1,095.23)	(1,095.23)	(1,095.23)	(1,095.23)	(794.74)	(386.34)	-	-	-	(94,152.56)	(47,709.01)
x	Non-Embedded CO2 Cost	$ / MWh		2015 AESC. Exhibit 4-7	48.03	48.54	49.05	48.71	48.33	47.92	47.47	46.99	46.47	45.91	45.30	44.66	43.97	54.23	55.31	56.41	57.53	58.68	59.84	61.03	62.24	63.48	64.74	66.03	67.34	68.68	70.05	71.44	72.86	74.30		
=	**Electricity Added Carbon Benefits**	$		**Calculated**	$ (76,908)	$ (169,566)	$ (272,075)	$ (270,165)	$ (268,069)	$ (265,782)	$ (263,328)	$ (260,637)	$ (257,733)	$ (254,643)	$ (251,291)	$ (247,703)	$ (243,871)	$ (300,822)	$ (306,800)	$ (239,527)	$ (158,919)	$ (64,264)	$ (65,541)	$ (66,844)	$ (68,172)	$ (69,527)	$ (70,908)	$ (72,318)	$ (73,755)	$ (54,583)	$ (27,061)	$ -	$ -	$ -	$ (4,740,810)	$ (2,338,135)
		Increase in tons CO2		implied tons CO2 from addl electricity	(824)	(1,797)	(2,854)	(2,854)	(2,854)	(2,854)	(2,854)	(2,854)	(2,854)	(2,854)	(2,854)	(2,854)	(2,854)	(2,854)	(2,854)	(2,185)	(1,421)	(563)	(563)	(563)	(563)	(563)	(563)	(563)	(563)	(409)	(199)	-	-	-		
	Non-Embedded CO2 Cost	$ / metric ton		2015 AESC. Exhibit 4-7	93.36	94.34	95.34	94.67	93.94	93.13	92.27	91.33	90.31	89.23	88.06	86.80	85.46	105.41	107.51	109.64	111.82	114.04	116.31	118.62	120.98	123.38	125.84	128.34	130.89	133.49	136.14	138.85	141.61	144.42		
	Natural Gas CO2 Emissions per Unit	metric ton / MMBTU		source: EIA	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05		
	Natural Gas Usage Reduction	MMBTU		Calculated	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
x	Natural Gas CO2 Emissions Reduction	metric tons		Calculated	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
=	**Natural Gas Carbon Benefits**	$		**Portion of data needed is not available**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Fuel Oil CO2 Emissions per Unit	metric ton / MMBTU		https://www.eia.gov/tools/faqs/faq.cfm?id=73&t=11	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07		
	Fuel Oil Usage Reduction	MMBTU		Calculated	17,595.13	38,825.92	61,398.76	61,398.76	61,398.76	61,398.76	61,398.76	61,398.76	61,398.76	61,398.76	61,398.76	61,398.76	61,398.76	61,398.76	61,398.76	49,105.98	35,081.82	19,326.28	19,326.28	19,326.28	19,326.28	19,326.28	19,326.28	19,326.28	19,326.28	14,023.93	6,817.30	-	-	-		
x	Fuel Oil CO2 Emissions Reduction	metric tons		Calculated	1,287	2,841	4,492	4,492	4,492	4,492	4,492	4,492	4,492	4,492	4,492	4,492	4,492	4,492	4,492	3,593	2,567	1,414	1,414	1,414	1,414	1,414	1,414	1,414	1,414	1,026	499	-	-	-		
=	**Fuel Oil Carbon Benefits**	$		**Portion of data needed is not available**	$ 120,187	$ 268,000	$ 428,283	$ 425,276	$ 421,977	$ 418,376	$ 414,514	$ 410,278	$ 405,706	$ 400,842	$ 395,565	$ 389,917	$ 383,885	$ 473,533	$ 482,944	$ 393,929	$ 287,020	$ 161,259	$ 164,464	$ 167,732	$ 171,066	$ 174,465	$ 177,933	$ 181,469	$ 185,075	$ 136,967	$ 67,906	$ -	$ -	$ -	$ 8,108,566	$ 3,817,704
	Propane CO2 Emissions per Unit	metric ton / MMBTU		NY BCA model	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06	0.06		
	Propane Usage Reduction	MMBTU		Calculated	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
x	Propane CO2 Emissions Reduction	metric tons		Calculated	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
=	**Propane Carbon Benefits**	$		**Portion of data needed is not available**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
=	**Benefit from Reduced Greenhouse Gas Externality Cost**	$	x	Portion of data needed is not available	$ 43,279	$ 98,434	$ 156,207	$ 155,111	$ 153,908	$ 152,594	$ 151,186	$ 149,640	$ 147,973	$ 146,199	$ 144,274	$ 142,214	$ 140,014	$ 172,712	$ 176,144	$ 154,402	$ 128,101	$ 96,995	$ 98,923	$ 100,889	$ 102,894	$ 104,939	$ 107,024	$ 109,151	$ 111,320	$ 82,384	$ 40,844	$ -	$ -	$ -	$ 3,367,756	$ 1,479,569
	net reduction in co2 (metric tons)				464	1,043	1,638	1,638	1,638	1,638	1,638	1,638	1,638	1,638	1,638	1,638	1,638	1,638	1,638	1,408	1,146	851	851	851	851	851	851	851	851	617	300	-	-	-		
	Criteria Air Pollutant and Other Environmental Costs																																			
	Natural Gas SO2 Emissions per Unit	short ton / MMBTU		EPA	2.90698E-07	2.90698E-07	2.90698E-07	2.90698E-07	2.90698E-07	2.90698E-07	2.90698E-07	2.90698E-07	2.90698E-07	2.90698E-07	2.90698E-07	2.90698E-07	2.90698E-07	2.90698E-07	2.90698E-07	2.90698E-07	2.90698E-07	2.90698E-07	2.90698E-07	2.90698E-07	2.90698E-07	2.90698E-07	2.90698E-07	2.90698E-07	2.90698E-07	2.90698E-07	2.90698E-07	2.90698E-07	2.90698E-07	2.90698E-07		
	Natural Gas NOX Emissions per Unit	short ton / MMBTU		EPA	-4.55426E-05	-4.55426E-05	-4.55426E-05	-4.55426E-05	-4.55426E-05	-4.55426E-05	-4.55426E-05	-4.55426E-05	-4.55426E-05	-4.55426E-05	-4.55426E-05	-4.55426E-05	-4.55426E-05	-4.55426E-05	-4.55426E-05	-4.55426E-05	-4.55426E-05	-4.55426E-05	-4.55426E-05	-4.55426E-05	-4.55426E-05	-4.55426E-05	-4.55426E-05	-4.55426E-05	-4.55426E-05	-4.55426E-05	-4.55426E-05	-4.5543E-05	-4.5543E-05	-4.5543E-05		
x	Natural Gas Usage Reduction	MMBTU		Natural gas is not used in base case and thus not replacec	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
=	Natural Gas SO2 Emissions Reduction	short tons		Calculated	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
=	Natural Gas NOX Emissions Reduction	short tons		Calculated	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-														
	Fuel Oil SO2 Emissions per Unit	short ton / MMBTU		https://www3.epa.gov/ttnchie1/conference/ei12/area/hane	0.000153791	0.000153791	0.000153791	0.000153791	0.000153791	0.000153791	0.000153791	0.000153791	0.000153791	0.000153791	0.000153791	0.000153791	0.000153791	0.000153791	0.000153791	0.000153791	0.000153791	0.000153791	0.000153791	0.000153791	0.000153791	0.000153791	0.000153791	0.000153791	0.000153791	0.000153791	0.000153791	0.000153791	0.000153791	0.000153791		
	Fuel Oil NOX Emissions per Unit	short ton / MMBTU		https://www3.epa.gov/ttnchie1/conference/ei12/area/hane	6.49819E-05	6.49819E-05	6.49819E-05	6.49819E-05	6.49819E-05	6.49819E-05	6.49819E-05	6.49819E-05	6.49819E-05	6.49819E-05	6.49819E-05	6.49819E-05	6.49819E-05	6.49819E-05	6.49819E-05	6.49819E-05	6.49819E-05	6.49819E-05	6.49819E-05	6.49819E-05	6.49819E-05	6.49819E-05	6.49819E-05	6.49819E-05	6.49819E-05	6.49819E-05	6.49819E-05	6.49819E-05	6.49819E-05	6.49819E-05		
x	Fuel Oil Usage Reduction	MMBTU		Calculated.	17,595.13	38,825.92	61,398.76	61,398.76	61,398.76	61,398.76	61,398.76	61,398.76	61,398.76	61,398.76	61,398.76	61,398.76	61,398.76	61,398.76	61,398.76	49,105.98	35,081.82	19,326.28	19,326.28	19,326.28	19,326.28	19,326.28	19,326.28	19,326.28	19,326.28	14,023.93	6,817.30	-	-	-		
=	Fuel Oil SO2 Emissions Reduction	short tons		Calculated	2.71	5.97	9.44	9.44	9.44	9.44	9.44	9.44	9.44	9.44	9.44	9.44	9.44	9.44	9.44	7.55	5.40	2.97	2.97	2.97	2.97	2.97	2.97	2.97	2.97	2.16	1.05	-	-	-	171.36	83.60
=	Fuel Oil NOX Emissions Reduction	short tons		Calculated	1.14	2.52	3.99	3.99	3.99	3.99	3.99	3.99	3.99	3.99	3.99	3.99	3.99	3.99	3.99	3.19	2.28	1.26	1.26	1.26	1.26	1.26	1.26	1.26	1.26	0.91	0.44	-	-	-		
	Propane SO2 Emissions per Unit	short ton / MMBTU		https://www3.epa.gov/ttn/chief/ap42/ch01/index.html	2.95622E-07	2.95622E-07	2.95622E-07	2.95622E-07	2.95622E-07	2.95622E-07	2.95622E-07	2.95622E-07	2.95622E-07	2.95622E-07	2.95622E-07	2.95622E-07	2.95622E-07	2.95622E-07	2.95622E-07	2.95622E-07	2.95622E-07	2.95622E-07	2.95622E-07	2.95622E-07	2.95622E-07	2.95622E-07	2.95622E-07	2.95622E-07	2.95622E-07	2.95622E-07	2.95622E-07	2.95622E-07	2.95622E-07	2.95622E-07		
	Propane NOX Emissions per Unit	short ton / MMBTU		https://www3.epa.gov/ttn/chief/ap42/ch01/index.html	7.11681E-05	7.11681E-05	7.11681E-05	7.11681E-05	7.11681E-05	7.11681E-05	7.11681E-05	7.11681E-05	7.11681E-05	7.11681E-05	7.11681E-05	7.11681E-05	7.11681E-05	7.11681E-05	7.11681E-05	7.11681E-05	7.11681E-05	7.11681E-05	7.11681E-05	7.11681E-05	7.11681E-05	7.11681E-05	7.11681E-05	7.11681E-05	7.11681E-05	7.11681E-05	7.11681E-05	7.11681E-05	7.11681E-05	7.11681E-05		
x	Propane Usage Reduction	MMBTU		Propane is not used in base case and thus not replaced	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
=	Propane SO2 Emissions Reduction	short tons		Calculated	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
=	Propane NOX Emissions Reduction	short tons		Calculated	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
	Total SO2 Emissions Reduction	short tons		Calculated	2.71	5.97	9.44	9.44	9.44	9.44	9.44	9.44	9.44	9.44	9.44	9.44	9.44	9.44	9.44	7.55	5.40	2.97	2.97	2.97	2.97	2.97	2.97	2.97	2.97	2.16	1.05	-	-	-		
x	SO2 Pollutant Cost	$ / short ton		AESC 2015 Exhibit 4.1. Emission Allowance Prices per Sh	1.20	1.25	1.30	1.35	1.41	1.46	1.52	1.59	1.65	1.72	1.79	1.86	1.93	2.01	2.09	2.18	2.26	2.36	2.45	2.55	2.65	2.76	2.87	2.99	3.11	3.23	3.36	3.50	3.64	3.79		
=	**Net Avoided SO2 Cost**	$		**Calculated**	$ 3	$ 7	$ 12	$ 13	$ 13	$ 14	$ 14	$ 15	$ 16	$ 16	$ 17	$ 18	$ 18	$ 19	$ 20	$ 16	$ 12	$ 7	$ 7	$ 8	$ 8	$ 8	$ 9	$ 9	$ 9	$ 7	$ 4	$ -	$ -	$ -	$ 319	$ 140
	Total NOX Emissions Reduction	short tons		Calculated	1.14	2.52	3.99	3.99	3.99	3.99	3.99	3.99	3.99	3.99	3.99	3.99	3.99	3.99	3.99	3.19	2.28	1.26	1.26	1.26	1.26	1.26	1.26	1.26	1.26	0.91	0.44	-	-	-		
x	NOX Pollutant Cost	$ / short		AESC 2015 Exhibit 4.1. Emission Allowance Prices per Sh	10.82	11.26	11.72	12.19	12.68	13.19	13.73	14.28	14.86	15.46	16.08	16.73	17.41	18.11	18.85	19.61	20.40	21.22	22.08	22.97	23.90	24.87	25.87	26.92	28.00	29.13	30.31	31.54	32.81	34.14		
=	**Net Avoided NOX Cost**	$		**Calculated**	$ 12	$ 28	$ 47	$ 49	$ 51	$ 53	$ 55	$ 57	$ 59	$ 62	$ 64	$ 67	$ 69	$ 72	$ 75	$ 63	$ 47	$ 27	$ 28	$ 29	$ 30	$ 31	$ 32	$ 34	$ 35	$ 27	$ 13	$ -	$ -	$ -	$ 1,215	$ 532
=	**Total Avoided Cost from SO2 and NOX Reduction**	$	x	**Calculated**	$ 16	$ 36	$ 59	$ 61	$ 64	$ 66	$ 69	$ 72	$ 75	$ 78	$ 81	$ 84	$ 88	$ 91	$ 95	$ 79	$ 59	$ 34	$ 35	$ 36	$ 38	$ 39	$ 41	$ 43	$ 44	$ 34	$ 17	$ -	$ -	$ -	$ 1,534	$ 672
	Non-Electric Avoided Fuel Cost																																			
	Natural Gas Consumption Cost	$ / MMBTU		https://www.eia.gov/outlooks/aeo/data/browser/#/?id=3-/	12.73	12.86	13.04	13.25	13.45	13.60	13.72	13.81	13.87	14.00	14.19	14.39	14.52	14.58	14.68	14.75	14.94	15.18	15.33	15.50	15.62	15.74	15.79	15.92	16.05	16.21	16.40	16.60	16.79	16.93		
x	Natural Gas Reduced Consumption	MMBTU		Calculated	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
=	**Natural Gas Avoided Cost**	$		**Calculated**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Fuel Oil Consumption Cost	$ / MMBTU		https://www.eia.gov/outlooks/aeo/data/browser/#/?id=3-/	20.15	21.22	21.69	22.07	22.34	22.67	22.99	23.46	23.83	24.02	24.06	24.28	24.73	25.14	25.63	25.55	25.85	26.07	26.59	26.67	26.83	27.20	27.40	27.44	27.49	27.55	27.65	27.74	27.91	28.25		
x	Fuel Oil Reduced Consumption	MMBTU		Calculated	17,595.13	38,825.92	61,398.76	61,398.76	61,398.76	61,398.76	61,398.76	61,398.76	61,398.76	61,398.76	61,398.76	61,398.76	61,398.76	61,398.76	61,398.76	49,105.98	35,081.82	19,326.28	19,326.28	19,326.28	19,326.28	19,326.28	19,326.28	19,326.28	19,326.28	14,023.93	6,817.30	-	-	-		
=	**Fuel Oil Avoided Cost**	$		**Calculated**	$ 354,515	$ 823,803	$ 1,332,007	$ 1,355,024	$ 1,371,428	$ 1,391,705	$ 1,411,297	$ 1,440,339	$ 1,462,879	$ 1,474,880	$ 1,477,392	$ 1,490,713	$ 1,518,683	$ 1,543,592	$ 1,573,676	$ 1,254,593	$ 907,034	$ 503,812	$ 513,945	$ 515,383	$ 518,567	$ 525,684	$ 529,480	$ 530,312	$ 531,315	$ 386,394	$ 188,495	$ -	$ -	$ -	$ 26,926,948	$ 12,737,349
	Propane Consumption Cost	$ / MMBTU		https://www.eia.gov/outlooks/aeo/data/browser/#/?id=3-/	20.39	20.43	20.37	20.38	20.82	21.10	21.19	21.15	21.19	21.39	21.45	21.47	21.64	22.07	22.39	22.45	22.69	22.80	23.14	23.30	23.61	24.05	24.21	24.47	24.61	24.81	24.99	25.07	25.26	25.46		
x	Propane Reduced Consumption	MMBTU		Calculated	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
=	**Propane Avoided Cost**	$		**Calculated**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
=	**Non-Electric Avoided Fuel Costs**	$	x	**Calculated**	$ 354,515	$ 823,803	$ 1,332,007	$ 1,355,024	$ 1,371,428	$ 1,391,705	$ 1,411,297	$ 1,440,339	$ 1,462,879	$ 1,474,880	$ 1,477,392	$ 1,490,713	$ 1,518,683	$ 1,543,592	$ 1,573,676	$ 1,254,593	$ 907,034	$ 503,812	$ 513,945	$ 515,383	$ 518,567	$ 525,684	$ 529,480	$ 530,312	$ 531,315	$ 386,394	$ 188,495	$ -	$ -	$ -	$ 26,926,948	$ 12,737,349
	Economic Development																																			
	Economic development (residential)																																			
	Economic development factor	$ / Total Resource Cost		RI Collaborative, RI EERMC. Email C. Lane, dated 10/24/1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
x	Total resource cost	$		Calculated	$ 2,782,449	$ 2,989,632	$ 3,223,932	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
=	**Total residential economic benefit**	$			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Economic development (commercial)																																			
	Economic development factor	$ / Total Resource Cost		RI Collaborative, RI EERMC. Email C. Lane, dated 10/24/1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-		
x	Total resource cost	$		Calculated	$ -	$ 965,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		
=	**Total commercial economic benefit**	$			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
=	**Total economic benefit (residential + commercial)**	$	x		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
	Increased Utility Revenue																																			
	Electricity Increase at Revenue	MWh		Need specific systems and specifications from NG	1,473.03	3,213.87	5,102.95	5,102.95	5,102.95	5,102.95	5,102.95	5,102.95	5,102.95	5,102.95	5,102.95	5,102.95	5,102.95	5,102.95	5,102.95	3,906.37	2,541.26	1,007.61	1,007.61	1,007.61	1,007.61	1,007.61	1,007.61	1,007.61	1,007.61	731.16	355.43	-	-	-		
x	Non-Bypassable Charges	$ / MWh		Confirm approach. Used Appendix B, wholesale + risk pr	$ 171	$ 181	$ 192	$ 204	$ 237	$ 245	$ 254	$ 265	$ 272	$ 279	$ 290	$ 302	$ 315	$ 326	$ 335	$ 344	$ 353	$ 362	$ 372	$ 383	$ 395	$ 407	$ 420	$ 433	$ 447	$ 460	$ 482	$ -	$ -	$ -		
=	**Increased Utility Revenue**	$	x	**Calculated Value**	$ 252,143	$ 581,787	$ 977,675	$ 1,040,401	$ 1,210,928	$ 1,250,397	$ 1,296,618	$ 1,353,368	$ 1,386,284	$ 1,425,385	$ 1,479,117	$ 1,542,917	$ 1,606,809	$ 1,662,625	$ 1,708,459	$ 1,343,760	$ 897,932	$ 364,288	$ 374,997	$ 386,196	$ 397,910	$ 410,165	$ 422,990	$ 436,413	$ 450,466	$ 336,324	$ 171,169	$ -	$ -	$ -	$ 24,767,521	$ 11,484,377

Attachment DIV 25-18
Electric Heat Workpaper 9.2

PREVIOUS TARGETS (INCORRECT)

ANNUALIZED CO2 Reductions

Program Design Element		Program Metrics	Target Levels	Targets (annual metric tons CO2) 2018	2019	2020
1.	GSHP Program	Carbon reduction (metric tons CO2 avoided per year)	Min	0	44	0
			Mid	**0**	**55**	**0**
			Max	0	66	0
2.	Equipment Incentives	Carbon reduction (metric tons CO2 avoided per year)	Min	119	134	156
			Mid	**149**	**168**	**195**
			Max	179	202	234

Final Targets (combined metric tons CO2 avoided per yer)

	2018	2019	2020
Min	119	178	156
Mid	**149**	**223**	**195**
Max	179	268	234

GSHP: 55.23 tons avoided CO2 expected per year of the system
Equipment Incentives: 149, 168, and 195 incremental tons annually for years 1, 2, 3

REVISED TARGETS (CORRECTED)

Program Design Element		Program Metrics	Target Levels	Targets (annual 2018	2019	2020
1.	GSHP Program	Carbon reduction (metric tons CO2 avoided per year)	Min	0	47	0
			Mid	**0**	**59**	**0**
			Max	0	71	0
2.	Equipment Incentives	Carbon reduction (metric tons CO2 avoided per year)	Min	137	155	179
			Mid	**171**	**194**	**224**
			Max	206	232	269

Final Targets (combined metric tons CO2 avoided per yer)

	2018	2019	2020
Min	137	202	179
Mid	**171**	**253**	**224**
Max	206	303	269

GSHP: 59 tons avoided CO2 expected per year of the system
Equipment Incentives: 171, 194, and 224 incremental tons annually for years 1, 2, 3

Change in Targets (absolute)	2018	2019	2020
Min	18	24	23
Mid	**22**	**30**	**29**
Max	27	36	35

Change in Targets (percentage)	2018	2019	2020
Min	15%	13%	15%
Mid	**15%**	**13%**	**15%**
Max	15%	13%	15%

Attachment DIV 25-18

Electric Heat Workpaper 9.2 Assumptions

Assumptions				
Carbon Emissions Factors - non-electric fuels				
Fuel	**Lbs / MMBTU**	**Short Ton / MMBTU**	**Metric Ton / MMBTU**	**Source**
Natural Gas	117	0.0585	0.0530704	https://www.eia.gov/tools/faqs/faq.cfm?id=73&t=11
Fuel Oil	161.3	0.08065	0.0731645	https://www.eia.gov/tools/faqs/faq.cfm?id=73&t=11
Propane	139	0.0695	0.0630494	https://www.eia.gov/tools/faqs/faq.cfm?id=73&t=11

	Metric tons C	**% reduction**	
Average annual emissions of an oil-heated home	~8	n/a	3855
Average annual avoided CO2 from oil-to-ccASHP conversion	~3	38%	282.0493
Average annual avoided CO2 from oil-to-GSHP conversion	~5	63%	

	2017	2018	2019	2020	2021
Medium Target:					
EE Measure Lifetime (years)		9.5	9.8	11.4	11.4
EE Energy Savings (lftm MWh)		1,712,064	1,904,592	2,160,318	2,160,318
EE Energy Savings (MWh)	201,347	179,968	194,677	189,509	189,509
EE Capacity Savings (MW)	29	30	35	34	34
EE Benefits ($1000)		$373,005	$438,942	$451,783	$451,783
EE Funding ($1000)		$115,547	$124,932	$109,090	$109,090
EE Net Benefits (before incentive)		$257,458	$314,010	$342,693	$342,693
Costs as % of Benefits		31%	28%	24%	24%
EE COSE ($/MWh)		7.1	7.7	6.2	6.2
EE Incentive ($1000)		5,777	6,247	5,455	5,455
Maximum Target:					
Scale-up factor			1.06	1.12	1.12
EE Energy Savings (MWh)			205,801	211,804	211,804
EE Capacity Savings (MW)			37	38	38
EE Funding ($1000)			132,071	121,924	121,924
EE Incentive ($1000)			6,604	6,096	6,096

Notes:
Nat Grid Workpaper 9-1, page 3 has EE MW targets that are the same as the Three-Year Plan
It also has EE MW Max targets. They are presented above.
The rest of the max target information is just scaled up by the same ratio as MW.

Table From National Grid 2018-2020 Three-Year EE Plan

Electric Programs	2018	2019*	2020
Savings and Benefits			
Annual MWh Savings	179,968	194,677	189,509
Lifetime MWh Savings	1,712,064	1,904,592	2,160,318
Savings as a Percent of 2015 Sales	2.40%	2.60%	2.53%
Annual Peak kW Savings	29,639	35,188	34,224
Winter Peak kW Savings	29,092	26,517	28,466
Total Benefits (RI Test)	$ 373,004,694	$ 438,942,301	$ 451,782,884
Costs			
Total Funding Required	$ 115,547,860	$ 124,932,991	$ 109,090,025
Cents per lifetime kWh	$ 0.071	$ 0.077	$ 0.062
EE Program Charge per kWh	$ 0.01090	$ 0.01390	$ 0.01193
Benefit Cost Ratio (RI Test)	2.93	2.88	3.23
Participation	TBD	TBD	TBD

*2019 includes 25,539 Annual MWh and correlated costs and benefits, as an adder for future innovation.

CERTIFICATION

I hereby certify that on April 25, 2018, I sent a copy of the within to all parties set forth on the attached Service List by electronic mail and copies to Luly Massaro, Commission Clerk, by electronic mail and regular mail.

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