STATE OF RHODE ISLAND AND PROVIDENCE PLANTATIONS

BEFORE THE PUBLIC UTILITIES COMMISSION

IN RE: REVIEW OF THE NARRAGANSETT ELECTRIC COMPANY

D/B/A NATIONAL GRID'S DISTRIBUTION RATE FILING

PURSUANT TO R.I. GEN. LAWS § 39-1-1 et seq.

DOCKET NO. 4770

PREFILED DIRECT TESTIMONY

OF

KARL R. RÁBAGO

EXECUTIVE DIRECTOR, PACE ENERGY AND CLIMATE CENTER

on behalf of

NEW ENERGY RHODE ISLAND

APRIL 6, 2018

TABLE OF CONTENTS

INTRODUCTION AND BACKGROUND

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

A. My name is Karl R. Rábago. I am executive director of the Pace Energy and Climate Center ("Pace"), a project of the Pace University Elisabeth Haub School of Law, with offices located at 78 North Broadway, White Plains, New York.

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

A. I am testifying on behalf of New Energy Rhode Island ("NERI").

Q. Please summarize your education and work experience.

A. I earned a B.B.A. in management (1977) from Texas A&M University, a J.D. with honors (1984) from the University of Texas School of Law, and LL.M. degrees in military law (1988) and environmental law (1990) from, respectively, the U.S. Army Judge Advocate General's School and Pace University School of Law. I served for more than twelve years as an officer in the U.S. Army, including in the Judge Advocate General's Corps and as an assistant professor of law at the United States Military Academy at West Point, New York. I have also worked for more than 20 years in the electricity industry and related fields. I have served as a Commissioner with the Texas Public Utility Commission (1992-1994) and as a Deputy Assistant Secretary for the Office of Utility Technologies with the U.S. Department of Energy (1995-1996). More recently, I have served as Director of Government and Regulatory Affairs for the AES Corporation (2006-2008) and as Vice President of Distributed Energy Services for Austin Energy, a large urban municipal electric utility in Texas. In 2012, I founded and became the principal of Rábago Energy LLC. I also currently serve as Chairman of the Board of Directors of the Center for Resource Solutions (1997-present) and as a member of the

Board of Directors of the Interstate Renewable Energy Council (2012-present). I started as the Executive Director of the Pace Energy and Climate Center in May 2014. My education and work experience is set forth in detail on my resume, attached as **Exhibit 1**.

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

A. Yes, I filed testimony in Docket No. 4568, and participated in Docket No. 4600. I have also testified under oath, participated in regulatory proceedings, or made presentations before state legislative or regulatory bodies in Arizona, California, Colorado, Connecticut, Florida, Georgia, Hawaii, Iowa, Kentucky, Michigan, Minnesota, Missouri, New York, North Carolina, Virginia, and Wisconsin. A table of my former testimony is attached as **Exhibit 2**.

Q. What materials did you review in preparing this testimony?

A. I reviewed the Company's application and work papers, and other filings relevant to this proceeding. In addition, I reviewed applicable Rhode Island statutes, relevant Rhode Island court decisions, testimony that I have submitted in other regulatory proceedings, and related reports.

Q. What is the purpose of this testimony?

A. This testimony offers recommendations based on a review of the Distribution Rate Filing ("Application") submitted by Narragansett Electric Company ("Narragansett" or "Company") d/b/a National Grid before the Rhode Island Public Utilities Commission ("Commission"). This testimony approaches the Company's Application under two themes. First, whether the proposed rates and the underlying costs, tariff design, and tariff application are just and reasonable. Second, whether various aspects of the Company's proposed rates and rate changes are consistent with the Commission's work on Power

Sector Transformation ("PST"). While the Company's PST filing has been separated to another proceeding, this testimony addresses the question of whether the proposed rates and their application adequately reflects the Company's embracing of a strategic opportunity "to modernize the utility business model, deploy advanced meters, enhance distribution system planning, and pursue beneficial electrification."[1] That is, this testimony addresses rate case-specific issues. NERI will file separate testimony in Docket No. 4780 relating to the Company's PST proposal.

OVERVIEW

Q. What is your understanding of the statutory foundation for review of the Company's Application in this proceeding?

A. The Rhode Island General Laws § 39-1-1 states that it is the policy of Rhode Island "to provide fair regulation of public utilities and carriers in the interest of the public, to promote availability of adequate, efficient and economical energy, communication, and transportation services and water supplies to the inhabitants of the state, to provide just and reasonable rates and charges for such services and supplies, without unjust discrimination, undue preferences or advantages, or unfair or destructive competitive practices, and to co-operate with other states and agencies of the federal government in promoting and coordinating efforts to achieve realization of this policy."[2] In 1996, the Rhode Island Legislature found that greater competition and performance based ratemaking for regulated utilities in the electricity sector is in the public interest and would provide savings to customers and greater economic growth, and that it is the policy

[1] Rhode Island Division of Public Utilities & Carriers, Office of Energy Resources, and Public Utilities Commission, "Rhode Island Power Sector Transformation Phase One Report to Governor Gina M. Raimondo," (Nov. 2017) ("PST Report"), at p. 12.
[2] RI Gen. Laws § 39-1-1(b).

of the State to reduce fossil-fuel emissions and cost-effectively attain environmental standards, and maintain protections for low income customers as the sector is restructured.[3] In 2006, the Legislature found that restructuring in the electricity sector had not fully delivered on its promise and that the state's economy and the health and general welfare of its people benefit from reliable and least-cost energy supplies, and that it is necessary for Rhode Island to move beyond basic utility restructuring in order to secure, "to the maximum extent reasonably feasible, the benefits of reasonable and stable rates, least-cost procurement, and system reliability that includes energy resource diversification, distributed generation, and load management."[4]

Q. What key guidance has the Commission provided?

A. The Commission's Guidance Document issued in Docket 4600-A[5] directs the consideration of the following goals by both proponents and opponents in matters involving the Company:

- Provide reliable, safe, clean, and affordable energy to Rhode Island customers over the long term (this applies to all energy use, not just regulated fuels);
- Strengthen the Rhode Island economy, support economic competitiveness, retain and create jobs by optimizing the benefits of a modern grid and attaining appropriate rate design structures;
- Address the challenge of climate change and other forms of pollution;

[3] *Id.* at § 39-1-1(d).
[4] *Id.* at § 39-1-1(e).
[5] PUC Guidance Document, Docket No. 4600-A (Sep. 6, 2017).

- Prioritize and facilitate increasing customer investment in their facilities (efficiency, distributed generation, storage, responsive demand, and the electrification of vehicles and heating) where that investment provides recognizable net benefits;
- Appropriately compensate distributed energy resources for the value they provide to the electricity system, customers, and society;
- Appropriately charge customers for the cost they impose on the grid;
- Appropriately compensate the distribution utility for the services it provides;
- Align distribution utility, customer, and policy objectives and interests through the regulatory framework, including rate design, cost recovery, and incentives.

In addition, the Commission adopted principles to be applied in assessing the reasonableness of rate design:

- Ensures safe, reliable, affordable, and environmentally responsible electricity service today and in the future;
- Promotes economic efficiency over the short and long term;
- Provides efficient price signals that reflect long-run marginal cost;
- Identifies future rates and rate structures that appropriately addresses "externalities" that are not adequately counted in current rate structures;
- Empowers consumers to manage their costs;
- Enables a fair opportunity for utility cost recovery of prudently incurred costs and revenue stability;
- Ensures that all parties should provide fair compensation for value and services received and should receive fair compensation for value and benefits delivered;
- Constitutes a design that is transparent and understandable to all customers;

- Ensures that any changes in rate structures are be implemented with due consideration to the principle of gradualism in order to allow ample time for customers (including DER customers) to understand new rates and to lessen immediate bill impacts;
- Provides opportunities to reduce energy burden, and address low income and vulnerable customers' needs;
- Ensures consistency with policy goals (e.g. environmental, climate (Resilient Rhode Island Act), energy diversity, competition, innovation, power/data security, least cost procurement, etc.);
- Evaluates rate structures based on whether they encourage or discourage appropriate investments that enable the evolution of the future energy system.

The Phase I Power Sector Transformation Report states:

> *During the coming year, the recommendations of this report will begin the evolution of the power sector through a variety of regulatory vehicles. In particular, National Grid's distribution rate case filing expected in December 2017 represents a strategic opportunity to modernize the utility business model, deploy advanced meters, enhance distribution system planning, and pursue beneficial electrification.*

Q. How does this statutory and Commission guidance inform your review of the Company's Application?

A. My overall assessment is that this rate Application occurs at a critical moment in the history of electricity regulation and markets in Rhode Island. Rate cases can and should set the tone and establish the foundation for the implementation and realization of important policy priorities. Rates send price signals that influence customer behaviors and guide customer engagement with electricity service opportunities. While rates are based on historical, test-year costs, they also guide utility decisions and shape the relationship between the Company as a service provider and its customers. Proposed and existing rates must be examined in light of these important effects in order to lead to rates that are just and reasonable in light of state policy. In particular, this rate Application should be assessed against a standard of whether it supports Rhode Island's policy of moving beyond restructuring as it was understood in the past, toward implementation of Power Sector Transformation.

Q. What is your overall assessment of this rate Application?

A. Based on my participation in Commission Docket Nos. 4568 and 4600, my experience is the Company is staffed by some of the most professional and dedicated utility personnel that I have encountered in my experience in utility regulatory matters. The Company understands the issues facing the industry and the compelling drivers for change—for Power Sector Transformation—that are facing the industry. In light of this experience, my review of this Application reveals that the Company has not (???) internalized the concepts and imperatives of Power Sector Transformation. This rate Application is disappointing in its failure to reflect the changes that the Company must undertake in order to align its basic rate making functions with Rhode Island policy. In particular, I cite and address in detail a number of major shortcomings:

- The Application is devoid of any evidence of an effort to begin the process of transitioning from traditional cost of service rate making toward performance-based earnings models. This transition would enable the reduction of risk associated with operating a distribution utility that embraces and supports rate innovation and third-party and customer-driven market development.

- The Company's Application does not offer any proposals aimed at moderating requirements for electric plant and gas service investments in favor of competitive market growth. The Company has a history of increasing earnings and rate base investments despite flat revenue growth and proposes in this case several initiatives with unproven customer benefits and deleterious impacts on customer uptake of efficiency, distributed generation, and other distributed energy resources.
- The Company's proposals on return on equity not only fail to address the potential to reduce return on equity ("ROE") requirements through revenue stabilization mechanisms and performance-based earnings, it affirmatively denigrates the potential and reality that such measures could enhance the attractiveness of the Company to investors through revenue stabilization and upside earnings opportunities.
- The Company proposes regressive and DER-frustrating rate designs that increase non-bypassable fixed customer charges for residential and small commercial customers, weaken price signals encouraging more efficient use and self-generation, and appear designed primarily to extract monopoly rents.
- The Company relies on forecasting methods that assume that Rhode Island will fail to increase reliance on energy efficiency and clean distributed renewable energy generation.
- The Company has failed to optimize through its tariff design the opportunity to maximize the benefits of high-efficiency Light-Emitting Diode ("LED") streetlighting

and has not fully addressed the critical issues of fair compensation and regulatory lag attending to those technologies.

- The Company is advancing an expensive Gas Business Enablement spending plan that is not demonstrated to improve customers' ability to control their gas costs and make more efficient gas consumption decisions and investments.
- The Company seeks rate recovery for trade association dues to organizations that actively advocate for causes opposed to many aspects of Rhode Island policy.

In sum, while the Company's rate application does a lot of the rate making work that a utility must do in order to secure adequate revenues to support the provision of adequate and reliable electric service to Rhode Island customers, it is a rate application framed on outdated principals without due regard for the opportunity to seize a strategic opportunity to modernize the utility business model.

Q. What aspects of the Company's Application do you address in this testimony?

A. This testimony addresses the following issues:

- Whether the Company's rate case approach is justified in light of historical financial trends.
- Whether the Company's approach to return on equity, risk, and rate of return is reasonable and compatible with power sector transformation.
- Whether the Company's proposals to increase fixed charges, collect demand costs through the fixed charge for residential and small commercial customers, and change the low-income customer rate structures will have the effect of weakening the markets and price signals for investments in renewables and efficiency.

- Whether the Company's filing sends the appropriate price signals to develop distributed energy resource markets in support of Rhode Island's Power Sector Transformation goals.
- Whether the Company's forecasting assumptions and methodologies are reasonable and appropriately incorporate distributed energy resources, including streetlight conversions, in alignment with Rhode Island's Power Sector Transformation goals.
- Whether the Company's Streetlight Tariff fully and fairly compensates S-05 tariff customers for the benefits of their investments in qualifying efficient lighting.
- Whether the Company's proposed Gas Business Enablement investments are prudent and in ratepayers' interests.
- Whether the Company has demonstrated that the trade association dues it recovers from ratepayers are not used in support of lobbying activity, and whether recovery of those dues from ratepayers is in ratepayers' best interests.

HISTORICAL TRENDS AND THEIR SIGNIFICANCE IN THIS RATE APPLICATION

Q. What do you learn by reviewing the historical trends for the Company's operations in Rhode Island?

A. The Company provided data that illustrates key trends in electric operating revenue, electric plant in service, and operating income.[6] Taken together, this data paints a picture of a utility company that its experiencing relatively flat sales, but that has nevertheless managed to consistently increase both its electricity rate base and its operating income.

[6] Company response to NERI 2-9.

Figure 1: Electric Operating Revenue

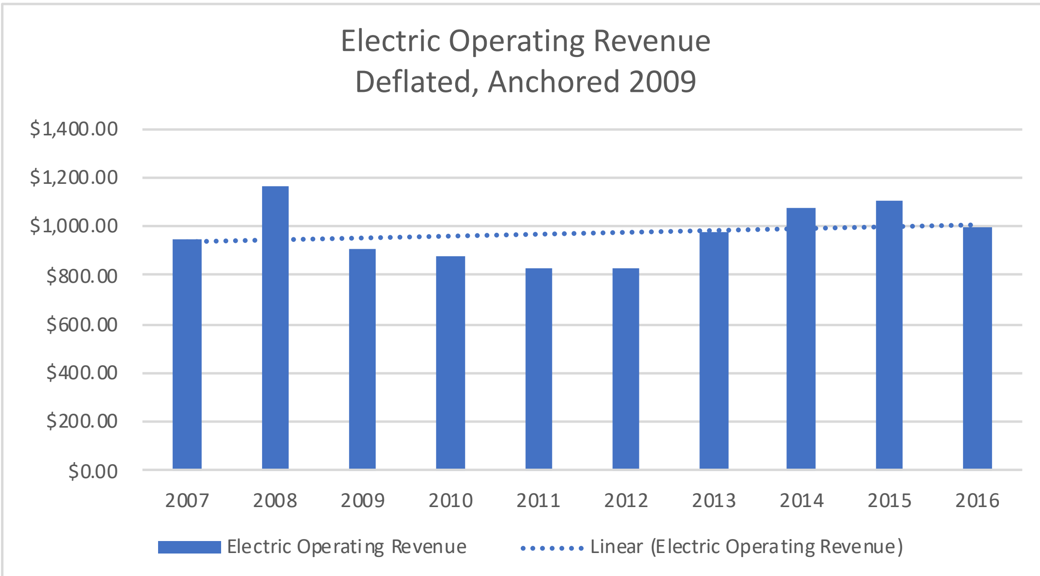


Figure 2: Net Electric Plant in Service

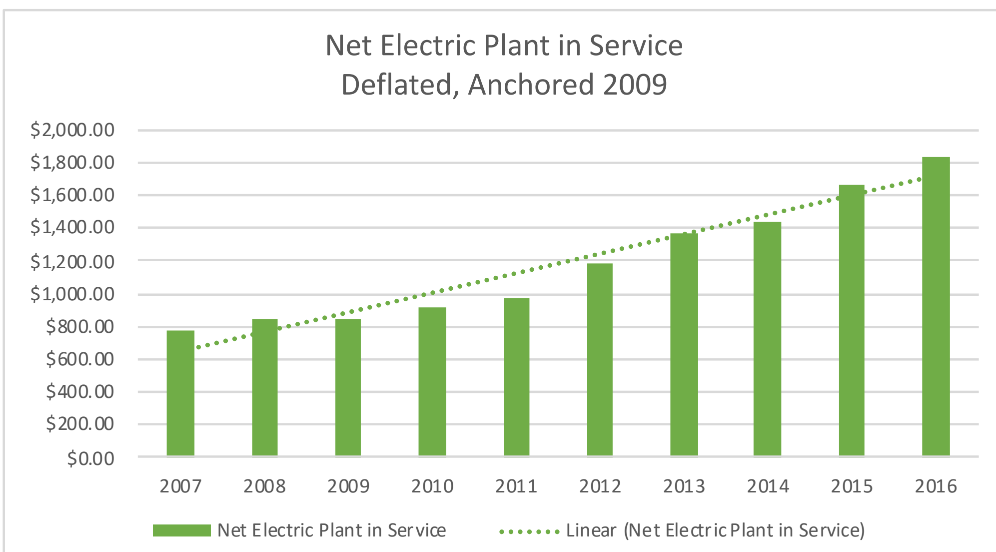
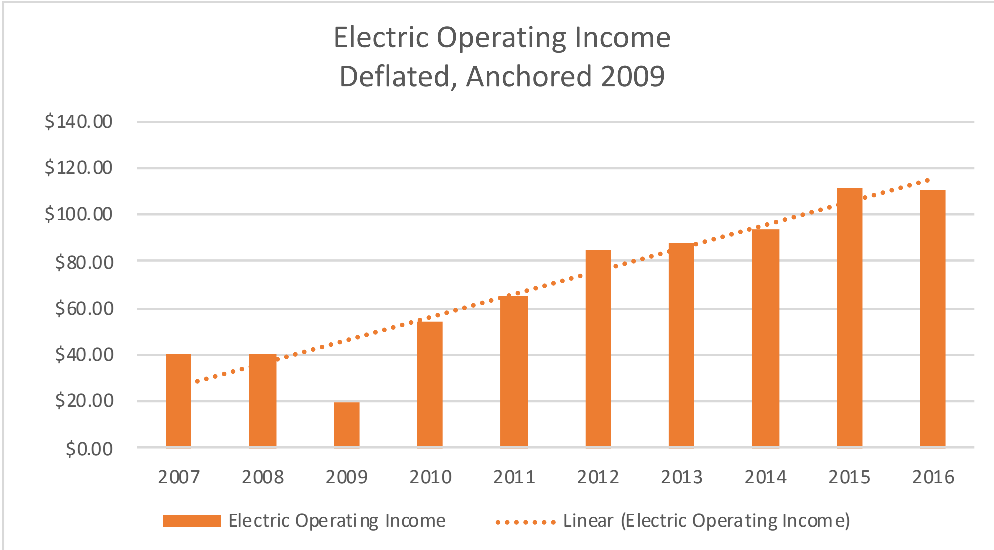


Figure 3: Electric Operating Income



Q. Why are these high-level trends significant?

A. Operating an electric utility in a traditional manner is costly and requires significant capital investments. Reasonable income and profits attract affordable financing for these investments and enable additional investments in modernization and service improvement. But distribution utilities operate as a monopoly and have a strong financial incentive to grow revenues through rate base expansion. Traditionally, electric utilities have funded capital expansions and revenue growth through year-over-year increases in sales. System-wide economies of scale favored large solutions over small ones, centralized investments over distributed ones, utility investments over customer investments. With flat electricity sales trends, a new approach is required. The data strongly suggests that the Company is headed in the wrong direction in Rhode Island.

Q. What are the options for an electric distribution utility facing these trends?

A. The Company faces a challenge. Because revenues are flat, the traditional utility model, even for a restructured utility that does not own generation, offers little hope of continuing to increase returns to shareholders (income) through increasing capital investments (net plant) absent a willingness on the part of regulators to maintain and enhance revenue stabilization mechanisms, or to pass along revenue increases and increased rates of return (increased revenues). In the electric industry today, many utilities seek revenue security through increased fixed customer charges, the collection of demand-related costs through fixed charges, increased rates of return, and the dampening or elimination of price signals encouraging more efficient consumption and self-generation. In economic terms, the traditional monopoly will seek to increase the collection of economic rents.

Q. Is there any alternative to the traditional approach?

A. There are alternatives. As recognized by both the Rhode Island Legislature and the Commission, the Company could embrace and begin to actualize an agenda of transformation. Elements of this transformation include performance-based revenue models that displace cost of service approaches, increased emphasis on customer engagement, stronger encouragement of energy efficiency and other distributed energy resources ("DER") as an alternative to utility capital investments, and ultimately, market-based earnings derived from fair and competitive energy service markets. In the end, even higher rates could be justified by higher distribution platform service value and lower customer bills. But to get there, the Company will have to trend toward, and not away from, its own transformation, and to embrace a vision of improved economics for the Company and Rhode Island through this change.

Q. Do the proposals by the Company in this rate Application evince a transformation mindset in either Narragansett or National Grid?

A. Unfortunately, no. Several aspects of the Company's Application indicate that it is more focused on extending the life of the failed traditional distribution utility model than on embracing the opportunities of a new business model. Many of the detailed proposals in this regard are reflected in the Company's PST filing, where the Company proposes an inordinate degree of utility ownership and rate base building, for example. But the instant rate Application is replete with signs that the Company has not embraced a transformation vision. These errors are correctible in this proceeding.

Q. What should the Company seek to accomplish regarding its long term financial trends on a going forward basis?

A. The Company must accept and adapt to the reality that electricity sales growth is a thing of the past. Advanced energy efficiency and the compelling economics of DER in the hands of empowered customers mean that the value that customers realize for electricity bill payments must increase. The Company must take a leadership role in moving away from the traditional model where net plant investment directly correlates with utility income. Restructuring removed the electricity generation component of the traditional capital investment driver, but the Company must embrace a model in which non-utility and customer investments in distribution-level infrastructure and capability is as much a resource as utility-owned investments. Finally, the Company must embrace a model in which income is related to performance in achieving the Commission' priorities for electric service in Rhode Island. Appropriately crafted and implemented performance-based earnings should be fully integrated into the Company's rate application in order to obtain Commission approval.

Q. Do you address these changes with regard to specific aspects of the Company's Application?

A. Yes. In this testimony I address ways in which the Company is headed in the wrong direction, and how it can reset its path toward transformation.

RETURN ON EQUITY

Q. Did you review the Company's proposal for an allowed return on equity?

A. Yes. A summary of the Company's proposed cost of capital, including a proposal for a 10.10 percent Return on Equity ("ROE") is set forth in Figure 4, below, taken from the direct testimony of Company witness Melissa A. Little.[7] As Figure 4 demonstrates, the ROE is one component of the overall cost of capital, which also accounts for the cost of debt and preferred stock, and is weighted with those costs according to the target capital structure in order to yield the weighted Rate of Return. The Company retained a consultant, Robert B. Hevert, to provide testimony that recommends the proposed ROE.[8] Mr. Hevert testified on the same issue in the Company's 2012 rate case.[9]

Q. What experience do you draw on in your evaluation of the Company's ROE proposal?

A. My experience is based on several record decisions that I made as a public utility commissioner in utility rate cases, and my experience in electric utility regulation gained over the past twenty-five years of practice. I point out a number of flaws in the proposal that have the effect of unreasonably inflating the Company's proposed ROE and therefore find a much lower ROE appropriate.

---

[7] Prefiled testimony of Company witness Melissa A. Little, at Sched. MAL-1-ELEC (Book 9).
[8] Prefiled testimony of Company witness Robert B. Hevert (Book 2).
[9] *Id.* at p. 3.

Figure 4: Company Proposed Cost of Capital

The Narragansett Electric Company d/b/a National Grid
Cost of Capital
For the Test Year Ended June 30, 2017 and the Data Year 2 Ending August 31, 2021

	Description	Capital Structure	Cost Rate	Weighted Return	Taxes	Pre-tax Return
		(a)	(b)	(c) = (a) x (b)	(d)	(e) = (c)+(d)
1	Short Term Debt	0.45%	1.76%	0.01%		0.01%
2						
3	Long Term Debt	48.47%	4.69% (1)	2.27%		2.27%
4						
5	Preferred Stock	0.11%	4.50%	0.00%		0.00%
6						
7	Total Common Equity	50.97%	10.10%	5.15%	2.77% (2)	7.92%
8						
9	Total Capitalization	100.00%		7.43%	2.77%	10.20%

Notes
(1) Company's Effective Cost of Long Term Debt
(2) Line 3(c) / 65% - Line 3(c)

Q. What principles should the Commission bear in mind when determining the appropriate allowed ROE for the Company.

A. The general principles guiding the setting of the allowed ROE are related to the setting of just and reasonable rates. These include: (1) capital attraction and utility profitability, (2) affordability of electric service, and (3) consistency with broader policy, especially in the current Rhode Island utility regulatory environment.

Q. How does the allowed ROE affect capital attraction and utility profitability?

A. While the overall cost of capital is a shorthand way of comparing the profitability of a utility, the cost of debt is generally determined by market conditions. The cost of preferred stock is a relatively minor additional consideration. Therefore, the allowed ROE is the appropriate major focus for evaluating whether the allowed return is sufficiently high to enable the Company to successfully compete for affordable capital to fund utility investments. The ROE also reflects the perceived risk associated with investing in the utility. As Narragansett is a wholly-owned subsidiary of National Grid, the allowed ROE for Narragansett impacts the ability and willingness of National Grid to make necessary investments in Rhode Island. Generally speaking, equity investors prefer a higher ROE. Also importantly, a high ROE will create an incentive for a utility to grow the rate base because the rate base earns return. This in turn may result in a kind of utility "reach for yield" where a utility unwisely pursues risky and ineffective capital investments in an effort to realize higher returns. Mr. Hevert assumes that utilities are on a constant search for ever-increasing capital investments, even under PST, and does not address the potential for DER, Power Sector Transformation, and performance-based rate making to reduce rate base investments while maintaining or even enhancing utility profitability.[10]

Q. How does the allowed ROE impact affordability?

A. The allowed rate of return is applied to the approved utility rate base. According to the Company's filing in this Application,[11] each basis point (one one-hundredth of a percent) translates into about an additional $76,000 in revenue requirement that must be recovered in rates in the proposed test year and 2019 rate year. By 2020, this amount increases to about $82,500 per basis point. That is, each percentage point change in the rate of return equals about $7.6 million or $8.25 million in revenue requirement in those years.

Q. How does the allowed ROE impact Rhode Island electricity sector policy?

---

[10] *See* Company responses to NERI 2-22, 2-23, 2-26.
[11] Prefiled testimony of Company witness Melissa A. Little, at Sched. MAL-1-ELEC (Book 9).

A. As previously described, Rhode Island policy, embodied both in General Law and the Commission's PST efforts, envisions a move beyond restructuring toward a transformed electricity sector. This transformation involves increasing reliance on performance-based revenues, growth of non-utility investments and markets, and continued focus on ensuring affordability of electric service. A major objective of PST should be the reduction in and diversification of risks faced by the utility in the current and evolving marketplace, to the benefit of the citizens and economy of Rhode Island.

Q. What is your opinion of the methodology used by Company witness Hevert in developing the proposed ROE of 10.10%?

A. The Company's proposal is flawed in several key respects, resulting in an excessively high ROE. Therefore, the proposal for a 10.10% ROE is not reasonable and will not support just and reasonable rates.

Q. Please state your concerns with the Company's approach to proposing the ROE of 10.10%.

A. My first concern is with the witness' proposal to reject the Constant Growth Discounted Cash Flow ("DCF") model for determining the ROE that the Commission has previously favored, and instead to adopt a Capital Asset Pricing Model approach that yields a much higher ROE. The reasons that Mr. Hevert gives for rejecting the lower ROE values generated by the Constant Growth DCF are unconvincing. First, he offers a somewhat subjective assessment that notwithstanding evidence of lower levels of perceived risk among utility investors, utility valuation levels, which have been relatively high, have been stretched by a "reach for yield." That is, these investors have chased higher yields without due regard to the added risk incurred by such behavior. While the reach for yield phenomena has been recognized as a factor in the financial crisis of 2007-2008, the losses suffered by investors in Bernard Madoff's Ponzi scheme, and among investors facing more binding regulatory capital requirements,[12] Mr. Hevert offers no reliable evidence that high utility stock prices have been associated with such behavior. Mr. Hevert also argues that higher utility valuations do not point to lower perceived risks associated with utility stocks because there is historical data that utilities traded at a discount to the market on price-to-earnings basis due to relatively low earnings growth in the sector and over the long run.[13] As indicated previously in Figures 1 through 3, the Company has in fact enjoyed income and electric plant growth over the past ten years in spite of flat revenue growth. Finally, Mr. Hevert asserts that "with the growth of distributed generation, it could be argued that utility operations are more risky then they have ever been."[14] This final assertion ignores the potential for performance based revenues and the risk reduction benefits of increased energy efficiency, electric vehicles, and other forms of DER that are integral to moving beyond restructuring into power sector transformation.[15]

Q. What other concerns do you have?

A. My next concern is with the proxy group that the Company witness uses to benchmark his ROE recommendation.[16] Narragansett is a wholly-owned subsidiary of National Grid that operates in a state adjacent and near to other U.S. distribution utilities operating in

---

[12] Mark Kolakowski, "Finance and Investing: Reaching for Yield," thebalance.com (Aug. 27, 2017), available at https://www.thebalance.com/reaching-for-yield-1286671.
[13] Prefiled testimony of Company witness Robert B. Hevert, at p. 12 (Book 2).
[14] *Id.*
[15] *See* Company response to NERI 2-8, citing a number of dated reports focused on the "death spiral" threat of DER and which do not address the potential benefits of Power Sector Transformation for utilities.
[16] *Id.* at p. 19 *et seq*.

the U.S., in Massachusetts and in New York. Both those states have aggressive regulatory efforts underway to advance versions of electricity sector transformation. All three distribution companies operate in partially-deregulated markets and are not vertically-integrated utilities. Mr. Hevert uses a proxy group of twenty-four utilities, many of which differ significantly from the Company. The proxy list includes utilities that do not operate in restructured markets and are not making efforts to undertake a transformation agenda.[17] It includes vertically integrated utilities with significant generation asset portfolios.[18] It includes utilities operating in energy-only nodal markets, utilities that do not operate gas distribution utilities, and one that operates on an island. Mr. Hevert states that there are no utilities that are exactly comparable to Narragansett, and so the proxy group includes many different utility types, reducing the analytical value of the proxy group. Mr. Hevert did not make adjustments to the values relating to these utilities and used raw market data about those utilities in his analysis. As a result, the data is not reliable for benchmarking the Company's ROE.

Q. Does the fact that Mr. Hevert uses average values for all the utilities in the proxy group mitigate the risk of distortion in establishing a benchmark for the Company's proposed ROE?

A. No. Without sub-categorizing the kinds of utilities in the proxy group and adjusting values to eliminate distortions caused by non-similar traits, there is no way of knowing whether the proxy group averages are meaningful as a basis for setting the appropriate

[17] *See* Company response to NERI 2-14. Mr. Hevert did not review the specific proxy group companies relating to power sector transformation activities, only noting the increasing trend among the states.

[18] *See* Company response to DIV 4-15 & PUC 3-6, where Mr. Hevert offers highly conditional support for the proposition that "[h]olding all else equal, an electric utility that owns generation may have more business risk than a distribution-only electric utility."

ROE for the Company. For example, in calculating a range of ROE's under the CAPM methods he proposes for adoption,[19] Mr. Hevert applies a risk premium calculation based on Bloomberg and Value Line Beta Coefficients for the proxy group of utilities.[20] Mr. Hevert uses a simple average of these values to calculate the Market Risk Premium he offers as a benchmark for the Company. A cursory review of the data reveals that Consolidated Edison, which, like Narragansett, operates both gas and electric distribution businesses in a restructured electricity market, and is going through the New York "Reforming the Energy Vision" process, has the lowest beta coefficients in the group. The highest beta values are found with vertically integrated utilities with significant coal or nuclear generating assets that are not undergoing power sector transformation or even basic restructuring (ALLETE, El Paso Electric, IDACORP, Otter Tail, PNM, and OGE).[21] Indeed, if a risk premium adjustment is appropriate, it appears that Narragansett and National Grid should have more in common with Con Ed than with El Paso Electric. Mr. Hevert's analysis also takes no account of the risk premium impact of the fact that Narragansett is a subsidiary of National Grid.

Q. Do you have other concerns?

A. Yes. Mr. Hevert applies a "small size premium" for Narragansett in his estimation of the reasonableness of his proposed ROE under the methods he used.[22] He characterizes the small size of Narragansett as a business risk that supports a higher ROE for the Company. Mr. Hevert estimates this premium to be 1.05% based on a comparison of groupings of the market capitalization values of the proxy group. He uses size premium data from the

[19] *Id.* at Sched. RBH-7.
[20] *Id.* at Sched. RBH-6.
[21] *Id.*
[22] *Id.* at p. 58 *et seq.* (Book 2).

Duff & Phelps 2017 Valuation Handbook Guide to the Cost of Capital to derive the small size premium based on an "Implied Market Capitalization" for Narragansett.[23] The implied market capitalization for Narragansett is derived by calculating the median market-to-book ratio for the proxy group of utilities and multiplying it by Narragansett's market capitalization.

Q. How does Mr. Hevert justify evaluating the Company as a small utility when it is part of a multi-national conglomerate power company, National Grid?

A. Mr. Hevert takes the view that Narragansett must be evaluated as a stand-alone company based on an unreasonable interpretation of the Rhode Island Decoupling Act,[24] which states that "[a]ctions taken by the Commission in the exercise of its ratemaking authority for electric and gas rate cases shall be within the norm of industry standards and recognize the need to maintain the financial health of the distribution company as a stand-alone entity in Rhode Island."[25]

Q. Why is Mr. Hevert's approach unreasonable?

A. The treatment of Narragansett as a stand-alone entity for purposes of developing a reasonable ROE is unreasonable for three reasons. First, the language of the Decoupling Act does not compel the approach taken by Mr. Hevert. The standard is that the Commission should recognize the need to maintain the financial health of Narragansett as a stand-alone company, not treat it as one in contravention to the facts. Narragansett's financial health and risk profile is assisted in material ways by its relationship with National Grid. Indeed, the premise of National Grid's acquisition of the New England

---

[23] Prefiled testimony of Company witness Robert B. Hevert, at p. 58-62 & Sched. RBH-9 (Book 2).
[24] *See* Company responses to NERI 2-3 & 2-5.
[25] R.I. Gen. Laws § 39-1-27.7.1.

Electric System and Narragansett was that the operating subsidiaries would continue to perform as local companies, and do so with the backing of a major multinational company.[26] Second, to ignore Narragansett's position as a wholly-owned subsidiary of National Grid would also ignore the reduced risk and other financial benefits that Narragansett enjoys because of its relationship to the parent company. Narragansett's financial health and risk profile is assisted in material ways by its relationship with National Grid. Third, Mr. Hevert's approach requires an interpretation of the statute that is at odds with itself. The statute requires that the Commission's actions be within the norm of industry standards. The norm of industry standards is to evaluate and set rates for the Company that reflect its actual financial and organizational posture, and not ignore these facts in favor of some hypothetical construct that does not exist in reality.

Q. What is your specific concern with Mr. Hevert's small size premium analysis?

A. While Mr. Hevert's small size premium analysis is interesting, it compounds errors in the witness' overall methods and therefore provides no supporting justification for the reasonableness of the proposed ROE. First, the characterization of Narragansett as a small utility ignores the fact that it is a wholly-owned subsidiary of National Grid. Second, the methodology derives reference values from the entire, unadjusted proxy group data. As already explained, the proxy group data has not been refined to serve as an appropriate benchmark for Narragansett, whether considered as a stand-alone utility or as

[26] According to Rick Sergel, president and chief executive officer of NEES: "For NEES and our employees, this transaction not only keeps jobs in New England, it represents a tremendous opportunity for growth as the base of U.S. operations for a large and successful company." He also said: "Most important, our customers will continue to receive the same great service from the same people in the yellow trucks, 24 hours a day; and they will continue to receive rates among the lowest in the region. The only difference is that we will have the resources of an international leader behind us." Power Online, "National Grid Group is Acquiring New England Electric System," (Dec. 14, 1998), available at: https://www.poweronline.com/doc/national-grid-group-is-acquiring-new-england-0001.

a subsidiary of National Grid. Third, the analysis takes no account of the Commission's efforts to advance PST, which, with its emphasis on moving toward performance-based rate making, may actually favor a smaller utility.

Q. Do you have any other concerns with Mr. Hevert's approach?

A. Yes. Mr. Hevert asserts that notwithstanding the language of amendments to the Decoupling Act made by the Rhode Island legislature in S2675, dated July 12, 2016, the Commission should not account for the existence and operation of revenue stabilization mechanisms in place in Rhode Island when deciding upon a reasonable ROE for the Company.[27] Mr. Hevert takes this position based on two assertions. First, he asserts that the existence of revenue stabilization mechanisms in Rhode Island does not put the Company in a materially different position than that of the other utility members of the proxy group. Mr. Hevert states that among his proxy group utilities, all have fuel, purchased power, or gas cost recovery mechanisms; that eighteen of the utilities have infrastructure or capital cost recovery mechanisms in at least one subsidiary; and that eighteen of the utilities have full or partial decoupling mechanisms in place in at least one subsidiary.[28] These arguments based on a comparison to the proxy group selected by Mr. Hevert have the same problems already described regarding the many ways in which the proxy group utilities differ from the Company. In addition, the existence of fuel, purchased power, or gas cost adjustment mechanisms is a meaningless basis for comparison. Such mechanisms are common throughout the industry. The existence of mechanisms in "at least one operating subsidiary" is not meaningful when comparing to

[27] Prefiled testimony of Company witness Robert B. Hevert, at p. 65-71 (Book 2).
[28] *Id.* at 67.

either Narragansett as a stand-alone company or to National Grid, which owns operating subsidiaries in three northeast states with decoupling mechanisms.

Q. What is the second part of Mr. Hevert's argument and how do you respond to that?

A. The second prong of Mr. Hevert's argument is that he has not found evidence that investors have, in the past, reduced their return requirements as a direct consequence of revenue stabilization mechanisms,[29] though he did not conduct any analysis specific to the Company on whether revenue stabilization mechanism have impacted revenues because such an analysis would be "complex and significant."[30] Mr. Hevert's position is an argument for repealing revenue stabilization mechanisms in Rhode Island as ineffective in accomplishing their intended purpose. This argument fails for several additional reasons. The Commission is fully authorized under the amended Decoupling Act to consider the existence of revenue stabilization mechanisms as a factor in setting the allowed ROE. The burden of supporting its proposed ROE is on the Company, not the Commission. Mr. Hevert himself quotes Standard & Poors for the proposition that it has "seen many state commissions approve alternative ratemaking techniques to traditional base rate case applications, which help utilities sustain cash flow measures, earning power, and ultimately, credit quality."[31] Indeed, the policy of Rhode Island is to move beyond restructuring and, through Power Sector Transformation, implement performance-based rate making and other mechanisms designed to improve economic health. The Company's great success in implementing energy efficiency in Rhode Island is due, in large part, to the existence of decoupling.

[29] *See* Company response to NERI 2-28.
[30] *See* Company response to NERI 2-29.
[31] *Id.* at 68, citing S&P RatingsDirect, *Industry Economic and Ratings Outlook: U.S. Regulated Utilities Expected To Continue On Stable Trajectory In 2013*, dated January 25, 2013.

Q. Based on your review of the Company's proposal for an ROE of 10.10%, what do you recommend?

A. The Commission should reject the proposed 10.10% ROE. The Commission should approve an ROE that is at the lower end of the Company's Constant Growth DCF, that does not reflect a small size premium, and that reflects the existence of revenue stabilization mechanisms and proposals for performance-based revenues submitted by the Company. An ROE in the range of 8%, and no higher than 8.44%, would therefore be just and reasonable. In addition, the Commission should order the Company to develop a new ROE proposal when it next files a rate case consistent with these findings.

RESIDENTIAL, LOW-INCOME, AND SMALL COMMERCIAL RATE PROPOSALS

Q. What does the Company propose relating to residential rates, low-income residential customer rates, and small commercial rates?

A. The Company makes several proposals, including an increase in the fixed customer charge from $5 per month for rate A-16 residential customers to $8.50 per month, an increase of 70% in the fixed month charge; a phased-in increase in the rate A-60 fixed customer charge for low-income customers from $0 per month to $8.50 per month over three years; an increase in the fixed customer charge from $10 per month for rate C-06 customers to $13 per month, a 30% increase in the charge; a proposal to collect demand related costs from A-16, A-60, and C-06 customers through the fixed customer charge; and a proposal to implement a 15% discount for qualified low-income customers in place of the current base distribution charge rates. These proposals are unjustified and inconsistent with the Commission's efforts to implement Power Sector Transformation.

Q. What is the monthly bill impact of the proposed increase fixed customer charges?

A. The Company's bill impact estimates reveal that the greatest impact of the proposed fixed charge increases falls on the lowest users of electricity.[32] For example, for A-16 customers who use 150 kWh per month, the bill for all charges would increase by 12.5%, while the percentage increase for customers that use 2,000 kWh per month, the bill would increase by only 3.9%. After the 15% proposed discount and full implementation of the fixed customer charge, low-income customers on rate A-60 who use 150 kWh per month would see an increase of 8.3% after the fixed charge is phased in, compared to a bill increase of 0.8% for customers who use 2,000 kWh per month.

Q. Why is the fact that the proposed rate changes impose a greater burden on low energy users important?

A. Low energy users are often low-income customers, fixed-income customers, and the elderly, whether or not they are enrolled in a discount rate. Customers who make significant investments in energy efficiency and self-generation fall into this category as well. For these customers, proposed rate changes like those proposed by the Company are economically regressive. The issue is particularly important to NERI because many of these customers live in towns and cities that are part of the NERI group.[33]

Q. What data is available about energy usage levels and income in Rhode Island?

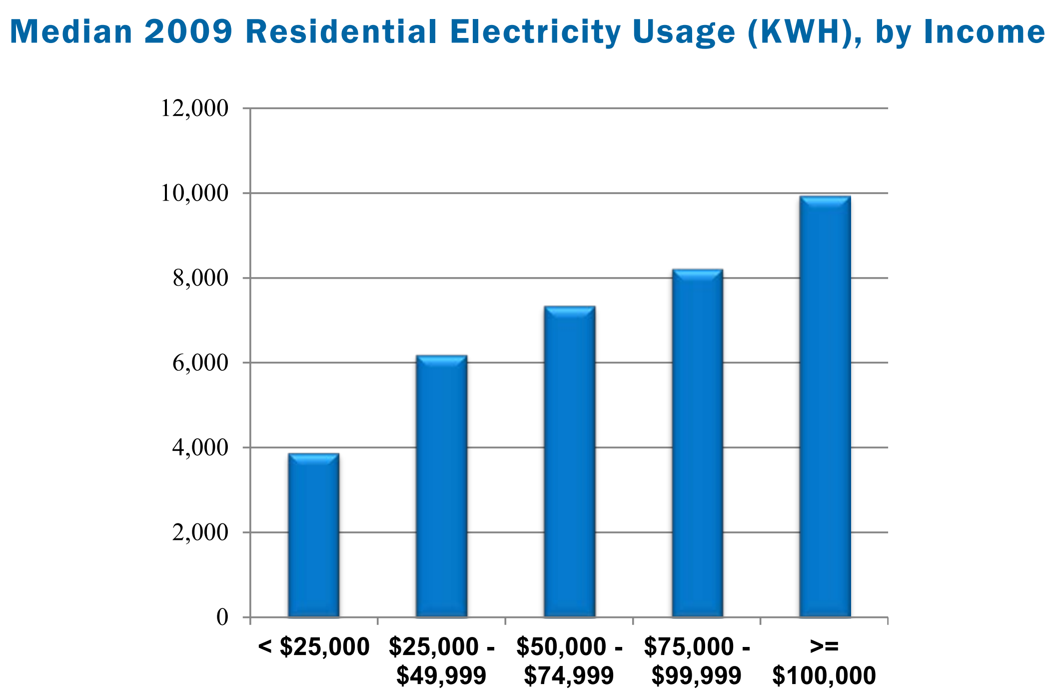
A. The Company did not address the relationship between energy usage levels and income in its rate Application. The Company asserts that because of "the lack of advanced metering functionality for residential customers in Rhode Island, the Company is not

---

[32] Prefiled testimony of Company witness Howard S. Gorman, at Sched. HSG-5-A – HSG-5-C (Book 12).
[33] *See* Company response to NERI 4-4.

currently able to undertake any detailed analysis of electricity usage patterns by income-eligible customers."[34] The Company does not indicate whether it has tried sampling techniques to arrive at estimates for energy usage patterns. The Company reports that the total population of low-income or "income eligible" customers is about three times as many as the number of customers enrolled in the A-60 rate.[35] According to data obtained from the U.S. Energy Information Administration's Residential Energy Consumption Survey for 2009, the most recent data available, and published by the National Consumer Law Center ("NCLC"), energy usage is directly related to household income in Rhode Island, Connecticut, Maine, New Hampshire, and Vermont. [36]

Figure 5: U.S. EIA Residential Energy Consumption Survey Data (RI, CT, ME, NH, VT) 2009



[34] *See* Company response to NERI 4-6.
[35] *See* Company response to NERI 4-2 & 4-3.
[36] "Utility Rate Design: How Mandatory Monthly Customer Fees Cause Disproportionate Harm," available at: http://www.nclc.org/images/pdf/energy_utility_telecom/rate_design/CT-FINAL2.pdf.

In addition, according to the U.S. EIA data, median electricity usage is also lower for households with residents older than 65 years, and for the homes of racial minorities.

Figure 6:

2009 Residential Energy Consumption by Income, Race/Ethnicity, & Age

HOUSEHOLD INCOME	MEDIAN ELECTRICITY USAGE (KWH)
< $25,000	3,904
$25,000 - $49,999	6,198
$50,000 - $74,999	7,358
$75,000 - $99,999	8,235
>=$100,000	9,957

HOUSEHOLD RACE	MEDIAN ELECTRICITY USAGE (KWH)
Asian	3,369
African American	5,967
Caucasian	7,266
Latino	4,794

HOUSEHOLD AGE	MEDIAN ELECTRICITY USAGE (KWH)
65 years or older	5,275
Less than 65 years	7,376

Q. How does the Company assign costs to the customer charge for residential and small commercial customers?

A. The Company asserts that it assigns costs as customer-related if those costs "vary with the number of customers and bear no relation to demand or usage," such as meters and related operation and maintenance costs.[37] At the same time, the Company asserts that customer-related costs are costs that are "primarily a function of the number of customers served, and bear no relation to demand or usage," and therefore includes as customer-costs the allocated portions of General Plant and Administrative & General ("A&G") costs. [38] General Plant costs so allocated amount to $10,307,000,[39] and A&G costs so

[37] Company response to NERI 7-4.c.
[38] *Id.* at NERI 7-4.a.
[39] Prefiled testimony of Company witness Howard S. Gorman, at Sched. HSG-1-D (Book 12).

allocated amount to $16,112,000[40] of a total $43,997,000[41] functionalized as Billing account costs. These two items do not vary solely with the number of customers served but do bear a relation to demand.

Q. How would the proposed residential rates change if these General Plant and A&G costs were removed from the Billing account?

A. The General Plant and A&G costs assigned to the Billing function account represent $26,419,000 of the $43,997,000 functionalized as Billing costs. About 74% of Billing costs are allocated to residential customers.[42] Removing the General Plant and Administrative and General costs from the Billing account would result in a reduction of the residential customer charge by about $3.71 per customer per month, leaving a total of $5.90 in customer-related charges per month.[43]

Q. What do you conclude from this analysis?

A. I conclude that the Company's fixed residential customer charge should not be increased beyond $5.90 per customer per month.

Q. How would the proposed small commercial C-06 rates change if these General Plant and A&G costs were removed from the Billing account?

A. The General Plant and A&G costs assigned to the Billing function account represent $26,419,000 of the $43,997,000 functionalized as Billing costs. About 14.92% of Billing costs are allocated to residential customers.[44] Removing the General Plant and Administrative and General costs from the Billing account would result in a reduction of

[40] *Id.*
[41] *Id.* at Sched. HSG-1C-1.
[42] *See id.* at Sched. HSG-1C-1. Calculated as $32,624 / $43,997,000 = .74151 or 74.151%.
[43] *See id.* Calculated as $9.61 – (74.151% x (($10, 307,000 + $16,112,000)) / 5,284,666 bills = $3.71 per customer per month.
[44] *See id.* at Sched. HSG-1C-1. Calculated as $6,565,000 / $43,997,000 = .1492 or 14.92%.

the residential customer charge by about \$6.29 per customer per month, leaving a total of \$7.48 in customer-related charges per month.[45]

Q. What do you conclude from this analysis?

A. I conclude that the Company's fixed customer charge for small commercial customers should be reduced from the current \$10 per customer per month and should not be higher than \$7.48 per customer per month.

Q. Why is it important the Company rigorously limit classification of costs as customer-related only to those costs that vary exclusively with customer count and the cost to connect?

A. In a utility sector undergoing Power Sector Transformation, the range of services and functions performed by equipment and personnel in the provision of electric distribution services is expanding. For example, modern "smart" meters do not just measure consumption in the way that old analog mechanical meters did when it was first decided to include all meter costs in the customer charge. These modern meters also support energy efficiency, demand response, demand charges, and, in the future, the scheduling of electric vehicle charging and appliance controls when the meter serves as a communications platform for a modern electric grid. As such, categorizing all meter costs as customer-related is a simple answer that is simply wrong to the extent that any costs higher than the cost of consumption logging associated with meters are assigned to the customer category. Likewise, the costs associated with customer service staff will increase as these staff are increasingly engaged in referring customers to energy

[45] *See id.* Calculated as \$13.78 – (14.92% x ((\$10, 307,000 + \$16,112,000)) / 626,592 bills = \$7.48 per customer per month.

efficiency and bill management programs and assisting those customers in taking advantage of programs designed to reduce energy use and demand. For these reasons, a volumetric charge for all costs other than the costs to connect the customer to the grid is more efficient and fair.

Q. Does the use of volumetric rates to carry fixed costs present a financial integrity risk to the utility that should be remedied with higher fixed charges?

A. No. First, the ratemaking principle is that rates should reflect costs, not be perfectly aligned with cost structure. There is no statistical likelihood of any real risk to the Company's financial integrity due to some customers using less energy than the utility had forecast in the interval between rate cases. The adverse impact on low use, low-income, and fixed income elderly customers, as well as upon the economics of efficient use of energy, discussed later in my testimony, outweighs any hypothetical risk to the Company's earnings. It should be noted that any revenue variances could more reasonably be addressed through better forecasting, more frequent rate cases, and, in times of Power Sector Transformation, through the use of future test years.

Q. Why is it appropriate to continue recovering fixed costs through volumetric rates?

A. It is appropriate because of the price signal function of properly designed rates. Properly designed rates *reflect* properly allocated costs *and* send signals for efficient consumption in the future. Although there has been considerable "buzz" in the electricity sector about innovative rate designs, the Commission Report and Order and the Stakeholder Working

Group Final Report in Docket No. 4600 recognized that significant groundwork must be laid prior to implementing major changes in rate design at some point in the future.[46]

Q. What is your assessment of the Company's proposal to implement a fixed charge for demand-related costs for A-16, A-60, and C-06 rate customers?

A. The Company's proposal to collect demand-related costs through a fixed customer-charge bundled into the charge for customer-related costs is premature and unjustified. The Company's sole justification for the proposed demand-related charge is that "it is appropriate to include some portion of the demand-related costs in the monthly charge, in order to align the utility's revenue and costs more closely, and to help stabilize the utility's revenue and customers' costs."[47] The premise of the proposal is that because these demand-related costs are fixed, the charge for these costs should be fixed, too.[48] Sunk fixed costs, which appears to be the focus of the Company's concern in its customer charge proposal, can be reflected in and collected through *either* the fixed charge or a volumetric charge. The Company recognizes this fact, as evidenced by its proposal to collect only "some" of the demand-related costs through a monthly charge. But an efficient price signal relating to future fixed costs can *only* be communicated with a volumetric charge given current conditions in the electricity sector in Rhode Island. That is why a volumetric charge is the optimal rate design for all demand-related distribution fixed costs allocated to residential and small commercial customers.

---

[46] Commission Report and Order 22851, In Re: Investigation into the Changing Electric Distribution System and the Modernization of Rates in Light of the Changing Distribution System, Docket No. 4600, at pp. 10-11 (Jul. 31, 2017); Docket 4600: Stakeholder Working Group Process Report to the Rhode Island Public Utilities Commission, at Ch. 3 (Apr. 5, 2017).
[47] Pre-filed testimony of Company witness Gorman, at p. 27 (Book 12).
[48] *See* Company response to NERI 7-14.

Q. Do you take issue with the way in which the Company calculates the amount of the proposed monthly charge for demand-related costs?

A. The Company proposal violates almost every tenet of economic efficiency and fair rate making underpinning the Commission's order in Docket No. 4600 and in the PST report. The Company proposal was put forward by Mr. Gorman.[49] It is based on a sample of 230 of the Company's 440,000 residential customers, and 153 of 52,000 small commercial customers. The Company did not demonstrate that these samples were scientifically based or statistically valid representatives of all customers. The Company then determined that what appears to the non-coincident demand of those customers exceeds .5 kW in at least one month per year for all residential customers, and exceeds .25 kW for almost all small commercial customers in at least one month per year. The Company did not address how this level of use by these customers caused costs incurred by the Company. Then the Company calculates the average demand-related costs per kW for all customers in the residential and small commercial classes and multiplies that cost by .5 and .25 for each class respectively. The Company did not address how these class-wide average costs related to actual costs created by any individual customer. This produced the amount of $5.78 for residential customers and $2.91 for small commercial customers. Using some math not explained by the Company, Mr. Gorman proposes to charge all residential and commercial customers some portion of these amounts. The Company did not explain what fraction of these amounts would be included in the monthly customer charge. The Company did not explain the basis or mechanism for its decision to combine its customer-cost numbers and its demand-related costs numbers and what fraction of

[49] *Id.*at pp. 25-31.

each of those amounts are to be collected from customers through the $8.50 or $13.00 customer charge. The Company did not address the price signal impacts of the proposed charges, but asserted that the charge could be larger. The Company conducted no evaluation of elasticity of demand.[50]

Q. Although the Company proposes to collect some amount of demand-related costs through a fixed monthly charge, does recovery of fixed costs through volumetric charges violate principles of ratemaking or sub-optimize the economic efficiency of rates?

A. No. Sound ratemaking is based on ensuring that costs are properly allocated to customer classes based on cost causation. I know of no ratemaking or economic principle that finds that cost *structure* must be replicated in rate *design*, especially when significant negative policy impacts are attendant to that approach. Traditional rate making limits residential and small commercial customer charges to certain basic customer connection costs—the consumption measurement function of the meter, billing services associated with account set up and disconnection, and other similar general and administrative costs that vary with customer count and with the cost to connect a customer to electric service. These fixed costs should form the basis and limit for fixed customer charges. Even so, when the policy impacts discussed below are considered, some of these costs (such as transformer costs) are best collected through variable charges.

Q. When costs associated with distribution systems are classified as fixed, should they be collected through the fixed customer charge?

[50] Company response to NERI 22-9.

A. Not necessarily, and not if the result is that low usage customers are disproportionately impacted, or that adverse impacts on energy efficiency, conservation, and renewables result, as discussed later in my testimony. Like the Company, some utilities have argued that increased fixed customer charges secure revenue recovery in a world where customers have more options to reduce their level of usage. I am not aware of any evidence or analysis, and see none in this record, that increasing fixed customer charges improves system-wide economic efficiency or the efficiency of *customer* decisions. Absent evidence of system-wide or customer efficiency benefits, fixed customer charges should not be increased, and demand-related costs should instead be allocated to volumetric charges. Again, the differences in costs that lead to labeling them as fixed or variable do not, standing alone, tell us anything about the rate design that should be used to recover them.

Q. What is the key difference between fixed and variable costs?

A. The key discriminator for labeling a cost as fixed or variable is the element of time. It is important to remember that over the long term, all costs are variable; just as over the very short term, one could argue all costs are fixed. For example, distribution transformers are typically treated as a fixed cost because of their relatively long life. Loading on a transformer, especially during periods of high demand, will impact its useful life. As a result, demand reductions can extend the useful life of transformers. In order to send a price signal that will encourage the reductions in demand that could extend useful life and reduce revenue requirements in the future, a volumetric rate should be used at this time to recover demand-related costs from small customers. Demand charges for these costs are appropriate for larger customers who have greater experience with and control over their usage levels and patterns.

Q. How do residential and small general service customers exercise control over their variable and fixed costs?

A. With volumetric rates to recover fixed and variable demand and energy costs, residential customers have meaningful, practical, and realistic opportunities to exercise control over their energy bills and costs. As discussed below, reductions in use—through efficiency, conservation, or self-generation—all contribute to reductions in variable energy costs. Moreover, these behaviors also reduce high peak demand, and by doing so customers directly contribute to reduced fixed costs going forward. Efficiency, demand response, west-facing solar, and other options allow customers to contribute to fixed cost reduction. All of these options are frustrated by shifting cost recovery for demand-related costs from volumetric to fixed monthly charges, as proposed by the Company. The overwhelming experience in the United States is that a utility can recover the exact same amount of authorized revenue requirement through a volumetric charge and avoid such unwelcome consequences.

Q. If the utility has costs that it classifies as fixed, should the charge to recover those costs be a fixed charge, in order to send a price signal to customers?

A. No. There is no meaningful price signal in charging a rate that few customers can effectively respond to through modification in behavior. Residential demand drives marginal distribution infrastructure investments and costs. Residential and small commercial customers have only limited options for changing their demand independently of their energy use, and this is especially true of renters; so volumetric energy rates are the best rate design option for sending price signals for both energy and demand cost causation on a going-forward basis. A customer's demand, especially for low-income and low use customers, is a function of the energy performance of their home, which is often rented; their major appliances, which are often expensive to replace or upgrade; and the weather. Imposing high fixed charges on these customers takes bread from their tables by increasing their energy burden and is the economic regulation equivalent of suggesting to customers in response, "Let them eat cake."

Q. What is your recommendation for a rate design that would recover increased costs that the Company proposes to collect through increased fixed customer charges?

A. The prudently incurred demand-related costs (above those strictly associated with the cost of connecting the customer to the grid) that the Company proposes to allocate to fixed customer charges should be allocated to volumetric rate elements unless and until the Company demonstrates the reasonableness of its proposed rate design in light of the potential adverse impacts discussed below, and after consideration of the relative impacts of alternative rate designs.

Q. Do the Company proposals to increase the fixed customer charge and impose a monthly charge for demand-related costs help to stabilize the Company's revenues?

A. It is understandable that the Company would try to fix a larger portion of its revenues collected from customers, but it is not reasonable. If a utility company forecasts greater demand for energy than it ends up experiencing, it will have an overbuilt system and experience a situation where sunk fixed costs are potentially stranded—not subject to recovery under current rates. The economically efficient solution is good price signals that do not undermine the economics of demand response and energy efficiency, better forecasting, and a smarter grid that leverages the potential benefits of all manner of distributed energy resources. As explained later in the section discussing impacts on energy efficiency and distributed generation, the Company residential and general service rate proposal not only constitutes the bad choice, it frustrates the good ones.

For example, if the utility forecasts that demand on a particular feeder will be heavy, it may install a larger, more expensive transformer. The money spent on that transformer will become a historical or sunk cost. Since the money is for a transformer, the costs will be treated as a fixed cost, and allocated accordingly. If demand does not match the forecast, the utility will face problems recovering the cost of the too-large transformer through volumetric rates. Of course, if the utility is guaranteed recovery of the costs through fixed charges, it will have no incentive to improve the accuracy of its forecasts. Importantly, the size of the *next* transformer and associated cost is a fixed cost that can be impacted by customer demand *in the future.* Energy efficiency, demand response, and other factors can reduce the fixed cost requirements in the future, and perhaps even allow for the installation of smaller replacement equipment. These measures can also extend the useful life of the installed fixed cost assets.

Further, it is widely accepted—and a strong justification for grid modernization investments—that customers can reduce the requirement for expensive infrastructure investments by reducing their usage during particular times of the day. These reductions arise because of reduction in system loading, which in turn reduces the need for costly system upgrades, reduces wear and tear (temperature-related degradation), and results in capital cost deferrals related to replacement. Higher volumetric charges for on-peak usage can support demand response programs and energy storage deployment with similar results.

Q. Did the Company evaluate how customer demand would or might change in response to changes in rates?

A. No. The Company states that it has not evaluated the issue of price elasticity of demand.[51] The Company did not produce customer usage information by household income for residential customers. The Company lacks a foundation on which to assert that its proposed rate design is just and reasonable.

Q. In summary, does the Company's proposal to disproportionately increase fixed customer charges constitute sound economics, regulation, and policy?

A. No. Peter Kind, known as the author of the Edison Electric Institute's "Disruptive Challenges" paper, recognized in a paper published in November of 2015 that "many utilities have been seeking to increase fixed charges, while customers and policymakers are vehemently opposed to such action. An evolved approach would focus on common ground with win4 (i.e. beneficial to customers, policy, competitive providers, and utilities) perspective."[52] As Kind further explained:

> *Adopting meaningful monthly fixed or demand charges system-wide will reduce financial risk for utility revenue collections for the immediate future, but this approach has several flaws that need to be considered when assessing alternatives through a win4 lens, by which all principal stakeholders benefit.*
>
> *Fixed charges:*

---

[51] *Id.*
[52] Peter Kind, "Pathway to a 21st Century Utility," CERES (Nov. 9, 2015), at p. 12.

- *do not promote efficiency of energy resource demand and capital investment;*
- *reduce customer control over energy costs;*
- *have a negative impact on low- or fixed-income customers; and*
- *impact all customers when select customers adopt [distributed energy resources] and potentially exit the system altogether, if high fixed charges are approved and the utility's cost of service increases.*[53]

The Company's proposed monthly charge proposals for residential and small commercial customers is bad for customers, policy, competitive providers, and even itself. It puts the Company's revenue recovery strategies in opposition to the best interests of its customers—an unsustainable posture in an increasingly competitive sector. Company witness Hevert recognizes that utility transformation could increase capital investment requirements without concomitant revenue increases.[54] Fixed charge increases are the wrong solution for that problem, especially in Rhode Island, where the Commission has clearly indicated a willingness to explore performance-based revenue models. As a recent report published by Consumers Union details, fixed charge proposals like those put forth by the Company in this case harm customers in several ways, violate fundamental principles of rate design, are unsupported by sound argument, and are inconsistent with regulatory trends around the country.[55]

[53] *Id.* at 30.
[54] Company response to NERI 1-4.
[55] M. Whited, T. Woolf, J. Daniel, "Caught in a Fix: The Problem with Fixed Charges for Electricity," prepared for Consumers Union (Feb. 9, 2016), available at: http://www.synapse-energy.com/sites/default/files/Caught-in-a-Fix.pdf.

Q. How does increasing fixed customer charges specifically impact customer investment in energy efficiency and conservation?

A. Increases in fixed customer charges create powerful price signals *against* investment in energy efficiency, conservation, and renewables.

Q. Did the Company consider the impact of its proposed increase in the fixed customer charge on energy efficiency, conservation, and renewables?

A. No. Rhode Island has been remarkably successful in developing its energy efficiency resources. According to the Company, energy efficiency programs have benefitted Rhode Island customers with $1.6 billion in electricity savings and $308 million in gas savings.[56]

Q. Why should the Commission be concerned about approving a rate design that is detrimental to energy efficiency, conservation, and renewables?

A. Energy efficiency, conservation, and renewables offer many benefits to the people and State of Rhode Island. These benefits include resource diversification, grid resiliency, future cost reductions associated with increased volume of deployment (economies of scale), job creation, system-wide cost reductions, and leveraging of non-utility investment dollars, among others.

Q. What "price signal" do fixed charges communicate to utilities?

A. Fixed prices for monopoly services communicate to the utility that regardless of the utility's spending levels, operational efficiency, or choice of resources for meeting demand for energy services, they can pass costs on to customers that cannot be avoided by reductions or efficiency in use by those customers.

---

[56] Company response to NERI 1-1.

Q. What result would you expect from allowing a monopoly electric utility to use fixed charges to recover fixed cost investments?

A. In a competitive market, a service provider would meet customer efforts to reduce and increase control over service bills with service innovations, operational efficiency, and price reductions. The logical result of using rate design to insulate a monopoly from market forces that would otherwise drive such benefits is that the monopoly will resist innovation and increase prices. In conclusion, the proposed increase in the fixed monthly charges for residential and small commercial customers are inimical to Rhode Island policy and the Commission's objectives in Power Sector Transformation.

Q. What action should the Commission take on the Company's monthly charge proposals?

A. I recommend that the Commission deny the Company proposals to increase the monthly charge for customer-related costs and to collect demand-related costs through the monthly customer charge. The Commission should direct the Company to remove General Plant and A&G costs from the Billing function and recalculate the monthly customer charge without those costs.

Q. What are your concerns about the Company proposals for rate design changes applicable to A-60 rate low-income customers?

A. For all the foregoing stated reasons, I find the Company proposal to assess the monthly customer charge on low-income customers especially unreasonable. The regressive effects of the monthly customer charge on low-use customers are such that for a customer using 150 kWh per month, the monthly charge will comprise, in Year 3, almost 25% of the monthly customer bill, even after a discount is applied. This means that the incentive for participating in energy efficiency measures would be significantly weaker for low-use customers, who are often low-income customers.

Q. What is your opinion of the proposal to apply a 15% discount to the entire bill for qualified low-income customers?

A. While I understand the simplicity benefits of a bill-wide discount, I am concerned that the approach will also weaken the price signals supporting energy efficiency and participation in other DER-related services, such as community shared solar.

Q. What do you recommend regarding these low-income proposals?

A. I recommend that the Commission disapprove the proposal to apply the monthly customer charge to low-income customers and the proposal to convert the low-income discount to a 15% applied to the total customer bill. The current discount approach for low-income customers should be retained, and the Commission should order the Company to launch and actively participate in further dialogue around addressing the critical issues of opportunities and challenges for low income customers in the context of electric utility rate making and Power Sector Transformation. As the George Wiley Center stated in its comments in response to the Commission's Notice to Accept Comments on the Draft Guidance Document in Docket No. 4600-A:

> *Docket 4600 and the Report, Order, and Draft Guidance Document that arose from it, signal the Commission's continued acknowledgement of the severity of the crisis of access to utilities that persists in Rhode Island. Many of the elements of the Draft Guidance document will help alleviate this crisis, but more work must be done. A dedicated review of the challenges facing low-income utility consumers in Rhode Island and a vigorous analysis of best practices for*

> *preventing involuntary termination and creating opportunity to access emerging technologies is necessary to meaningfully address this crisis.*[57]

FORECASTING ASSUMPTIONS AND METHODOLOGIES

Q. What are your concerns regarding the Company's forecasting assumptions and methodologies?

A. The Company's forecasting methods do not reflect an internalization of the goals and direction of Power Sector Transformation. In general, the forecasts appear to significantly undercount the potential impacts of energy efficiency, solar energy generation, and gas efficiency programs and market development.

Q. Why are forecasts important?

A. Accurately predicting the future is notoriously hard. But utilities must be as accurate as possible because poor forecasting can have enormous consequences on the utility, customers, and the economy. For example, under-forecasting the demand for electricity or gas can lead to under-investment in critical infrastructure and services, which can show up as outages, component failures, slow service response times, and even human injury and destruction of property. The conservative nature of the electricity industry, the professionalism and performance of the people who work for utilities, and advances in generation and grid technologies have significantly minimized the risks of under-investment. Over-investment, especially in utility-owned assets, can have pernicious economic and market development impacts. For example, the "cost-shift" that some assert results from the operation of net metered customer generation is a product of

[57] George Wiley Center Comments, PUC Guidance Document, Docket No. 4600-A (Sep. 6, 2017), available at: http://www.ripuc.org/eventsactions/docket/4600A-WileyCtr-Comments(6-9-17).pdf.

under-forecasting solar PV market penetration. That is, an accurate forecast that reflected the reduced sales of electricity that follow from customer generation, and the injections of exported energy from those generators would support more accurate rate setting.

Q. In what ways do you believe that the Company electricity and gas forecasts are deficient?

A. I have several specific concerns, and recommendations about how the forecasting methods used by the Company should be modified. However, I do not have the resources to replicate the forecasts with the changes that I propose. I identify these issues in support of a recommendation that the Commission charter an investigation or other proceeding into the issue of utility forecasting to inform future rate case filings.

Q. Please list and describe your concerns with the Company's forecasting methods.

A. My concerns are:

- The Company uses a ten-year average of daily temperature readings from 2007 to 2016 as the foundation for its forecast of cooling degree and heating degree days.[58] Given rising temperatures resulting from climate change, the use of a ten-year average is reasonable and preferable to the thirty-year averages that some utilities use. However, as temperatures have risen, so has the incidence of severe weather events. These events may have the effect of skewing averages used to weather-adjust forecasts. As a result, the Company should investigate the use of longer averages—say thirty years—in calculating the averages used for forecasts and in developing weather coefficients.[59]

[58] Prefiled testimony of Company witness Gredder, at p. 10 (Book 3).
[59] *See* Company response to NERI 3-2. The Company confirms that its position embeds the effects of severe weather events.

- The Company relies on weather normalization in order to develop forecasts of heating and cooling days, and ultimately, customer demand.[60] The changing climate, however, belies the reasonableness of even using the term "normal" when describing the weather. Given rising temperatures, normalization could have the effect of masking hotter summers, which could increase the penetration of air conditioning and demand), and warmer winters as well, which could reduce winter sales of electricity and gas for heat. Any attempt to use regression analysis on historical weather data to develop "normal" weather estimates should be complemented by alternative and possibly even innovative tools for assessing climate variability and trends and integrating this information into forecasts. The Company should investigate opportunities to adapt its methods to climate trends and supplement its assessment with alternative methods.
- The Company uses a forecasting process for electricity that backs out historical energy efficiency and solar PV generation from historical delivery data and then "reconstructs" these values with predictions of energy efficiency and solar PV impacts to develop the ultimate forecasts for delivery by class. While this method has the merit of not automatically extrapolating early-market penetration rates for efficiency and PV into forecasts—past performance may not necessarily indicate future performance—it puts a premium on using realistic forecasts of market growth for efficiency and solar PV. In this application, the Company forecasts declining growth in energy efficiency savings, based on its approved energy efficiency

[60] *Id.* At 11.

programs, for the years 2016-2021, falling from 17% in 2016 to 8% in 2021.[61] For years beyond the approved programs, the Company used ISO-NE data that forecasts an average 7% per year annual decline in energy efficiency program savings in both energy and demand.[62] The Company also projected a steady decline in solar PV market growth in Rhode Island, relying upon ISO-NE data that shows an average decline in the rate of new solar generation of 14% per year for the years 2019-2026.[63] These assumptions of declining growth in efficiency and solar PV are markedly out of step with the policy in Rhode Island and the Commission's agenda for Power Sector Transformation. They have the effect of potentially encouraging overbuilding and resulting in higher rates for customers. They also increase the potential for stranded costs. The Company should develop alternative scenario forecasts that align with Power Sector Transformation and increasing growth in DER markets, with a view toward developing more reasonable forecasts of energy sales.

- The Company's gas sales forecasts, like its electricity forecasting, rely on extrapolations of historical deliveries, adjusted for weather, economic conditions, and customer counts.[64] The Company's gas forecast methods are subject to many of the same concerns identified for electricity forecasts. Weather normalization methods should be reviewed for the potential impacts of increasing numbers of several weather events in the ten-year historical baseline. The Company should also review the weather normalization process to determine if the use of a ten-year historical forecast is adequate to capture climate change-related larger weather patterns. The Company

[61] *Id.* at 25-26 & Sched. JFG-10.
[62] *Id.* at JFG-9.
[63] *Id.* at 28 & Sched. JFG-15.
[64] Prefiled testimony of Company witness Poe (Book 3).

adjusts forecasts for the effects of efficiency, but because the Company has not seen any significant delivery reduction effects for residential customers due to efficiency programs, the forecast does not include any efficiency effects for those customers.

Q. What do you conclude based on your review of the Company's forecasting methods and the issues you reviewed?

A. The Company did not develop forecasts based on an expectation of Power Sector Transformation and its impacts. The Company's approach to forecasting is out of synch with the Commission's efforts and plans to advance Power Sector Transformation. They are based on declining energy efficiency and solar PV forecasts and assume no significant effects of gas efficiency efforts. In addition, the forecasts may not adequately capture the future impacts of climate change on weather.

Q. What should the Commission do?

A. I recommend that the Commission establish an investigatory or other proceeding to review and recommend improvements in utility forecasting, in particular to address the impacts of Power Sector Transformation and climate change.

APPLICATION OF THE STREETLIGHT TARIFF

Q. Did you review the Company's tariff applicable to energy efficient Light Emitting Diode streetlights?

A. Yes. In particular, NERI is focused on the Company's S-05 tariff[65] and its application to high-efficiency Light Emitting Diode ("LED") streetlights.

Q. Why do you raise the issue of street lighting in your testimony?

[65] R.I.P.U.C. No. 2179, Street and Area Lighting—Customer Owned Equipment S-05.

A. The passage of Rhode Island's Municipal Streetlight Investment Act[66] and the approval of the Company's S-05 tariff were significant steps toward recognizing the role of streetlights as a distributed energy resource that can empower municipalities to better manage their energy usage and costs. While the S-05 tariff has been the subject of review in other dockets, it remains a critical issue to municipalities, and the Company should approach it with the goal of continuously improving on the tariff's rate design and application to customers. In its *Guidance on Goals, Principles and Values for Matters Involving the Narragansett Electric Company* (the "Guidance Document"), the Commission identified a number of goals and rate design principles applicable to the Company's rates, a number of which are especially relevant to the S-05 tariff. In particular, the goals include "prioritiz[ing] and facilitat[ing] increasing customer investment in their facilities (efficiency, distributed generation, storage, responsive demand, and the electrification of vehicles and heating)," "appropriately compensat[ing] distributed energy resources for the value they provide to the electricity system, customers, and society," and "appropriately charg[ing] customers for the costs they impose on the grid."[67] Particularly relevant rate design principles include "promot[ing] economic efficiency over the short and long term," "provid[ing] efficient price signals that reflect long-run marginal costs," "empower[ing] customers to manage their costs," and developing rate design that "is transparent and understandable for all customers."[68] As further explained below, the current design and application of the S-05 tariff doesn't

[66] R.I. Gen. Laws §39-30-1-5.
[67] RI Public Service Commission, Public Utilities Commission's Guidance on Goals, Principles and Values for Matters Involving The Narragansett Electric Company d/b/a National Grid, at p. 4.
[68] *Id* at p. 4-5.

fully support the goals and rate design principles articulated in the Commission's Guidance Document.

Q. Why is the Street and Area Lighting—Customer-Owned Equipment Tariff of particular interest to NERI?

A. Several NERI members have an interest in high-efficiency customer-owned streetlights. NERI member Partnership for Rhode Island Streetlight Management assists Rhode Island municipalities with managing and operating their customer-owned streetlights; NERI member Washington County Regional Planning Council works with Rhode Island municipalities to address common goals and challenges, including in relation to municipal-owned streetlights; and NERI member the Rhode Island League of Cities and Towns is a membership organization supporting Rhode Island municipalities, including on issues relating to streetlights. In addition, NERI evaluated the form and application of the Street and Area Lighting Tariff as one of the strategic opportunities "to modernize the utility business model" as described in the PST Report. Proper and economically efficient pricing of electric services to modern LED streetlights is an outstanding early-stage distributed energy resources ("DER") case study. Controllable (dimmable) LED streetlights embody efficiency, and through municipal ownership and control, their use exemplifies customer empowerment, third party market development, and overall savings for all Rhode Islanders.

Q. Did the Company propose any changes to the S-05 tariff in this Application?

A. No, however, the tariff could be improved to enable greater energy savings and bill reductions. In addition, the Company must apply the tariff in a manner that fully recognizes and values investments in, and efficient management of, high-efficiency streetlights. These are issues that are germane to this general review of rates and tariffs.

Q. Please describe the Company's tariff applicable to Light Emitting Diodes.

A. The Company offers a non-metered, tiered billing structure for customers who take service under the S-05 tariff and transition to Solid State Lighting ("SSL") Sources, including LED lights. To determine the billable wattage for LEDs, the SSL Sources rate of the S-05 tariff applies seven billing tiers based on the nominal wattage range of the total device, including the LED array, driver, and control, plus applicable adjustments.[69]

Q. Does the S-05 tariff offer reduced rates for customers who operate their LED lights on dimmers?

A. Yes. The S-05 tariff provides a rate reduction for LED lights that are dimmed up to 30% below their nominal wattage for up to 4 hours per night.

Q. What are the benefits of operating LED lights on a dimming schedule?

A. LED lights require significantly less energy to operate than do incandescent or High Intensity Discharge ("HID") light sources, and dimming can increase the energy saving benefits of LED lights even further. Street lighting is often one of the largest expenses for municipalities, and municipal customers taking service under the S-05 tariff can significantly reduce their lighting budgets by transitioning to LEDs and maximizing the LED lighting's efficiency through automated, controllable dimming during nighttime hours.

---

[69] *Id* at Sheet 2.

Q. If S-05 customers wish to dim their LED lights more than 30% below nominal wattage or for more than 4 hours per night, would that additional decrease in delivered kWh be reflected as a reduction in the SSL Sources rate under the tariff?

A. No. Customers who wish to operate their LED lights more efficiently by increasing the degree of dimming or the length of the dimming period would not receive a higher discount under the SSL Sources rate to reflect the additional decreases in kWh delivered.

Q. Do you recommend any revisions to the tariff to correct for its deficiencies?

A. I recommend that the Company revise the S-05 tariff to permit customers to dim up to a higher percentage and for a greater number of hours under the SSL Sources rate, in order to maximize the efficiency benefits of LED lights operated on controllable dimmers. As a starting point, I would suggest increasing the dimming percentage to 50% below the nominal wattage, and the duration to 6 hours per night. Such an adjustment in the tariff would bring it into closer alignment with Rhode Island's Power System Transformation goals, as the tariff would send more robust price signals for customers to operate their LED lights with a higher degree of efficiency and would more accurately capture actual energy cost savings associated with customer use of smart control technologies.

Q. Why is it important that municipal streetlight owners and operators have clarity about the application of rates under the S-05 tariff, and that rates be truly cost-based?

A. Streetlights are an excellent early example, in the course of power system transformation, of highly efficient customer-owned DER. High-efficiency streetlights can deliver even greater savings when paired with controllable technology, and can empower customers, including municipalities, to manage their load in the manner that best serves their needs.

The opportunity to increase reliance on customer-owned DER, including high-efficiency street lighting, is consistent with Rhode Island policy and the Commission's Power Sector Transformation goals. The hallmark of successful DER market and customer enablement is that customers' engagement with the utility must be clear, transparent, and reflective of the cost of service and the value of DER. Customers must be able to understand how, and how much, they will be billed under the S-05 tariff, and be able to predict the consequences of changing their consumption patterns, including through dimming. When customers apply smart control technologies and increase the efficiency of their streetlights, their bills should show an appropriate and accurate reduction based on the value of those load-reducing actions. This type of relationship between the utility and customer-owned and -operated DER will be essential to successfully transforming Rhode Island's power sector.

Q. Are there any challenges associated with transitioning to high-efficiency, customer-owned streetlights?

A. Yes. Customer ownership of streetlights and the transition to LED lighting can pose challenges for traditional utility ratemaking. For this reason, high-efficiency, customer-owned LED lights represent an ideal technology for applying the rate design principles identified by the Commission in the Guidance Document.

Q. Please explain.

A. The Company's streetlight tariff is still in its early stages of application. As data becomes available on customer load and management practices under the SSL Sources rate, it is important to consider and apply the following rate design principles: First, rate design must be at least as flexible as the technology to which it applies. Second, the SSL Sources rate should be applied in such a way as to give full and fair compensation to customers for the value created by their efficient operation of high-efficiency streetlights. Third, the Company must acknowledge the great potential that regulatory lag will impact basic cost allocation decisions that go into the design of the S-05 tariff.

Q. Can you provide an example of how these principles might apply in practice?

A. For example, energy sales to streetlights as a class could fall significantly as more municipalities take service under the S-05 tariff and transition to LEDs with controllable dimmers. The Company's forecast already accounts for energy sales reductions attributable to streetlights, though it does not explicitly take into account municipal acquisition and management of streetlights, or the conversion to LEDs.[70] A decrease in sales directly attributable to municipal management of high-efficiency lighting means that any energy sales or demand allocators based on a historical usage would quickly become out of date. In addition, municipalities who acquire and manage their streetlights take on the maintenance, warehousing of replacement parts, work order processing, and other activities that would otherwise be performed by the Company, thus reducing the Company's administrative and general costs associated with those services. It is important for the cost of service study to accurately reflect those reductions. Without such adjustments, customers who adopt LEDs, with or without controllable dimmers, may not see the full benefits of the reduction in cost of service and would receive unfair treatment under the cost of service study. Regulatory lag could also potentially act as a disincentive to the adoption of efficient lighting.

Q. Based on your findings, what are your recommendations?

[70] *See* Company Response to NERI 23-1.

A. I recommend that the Company revise the S-05 tariff to permit customers to dim up to a higher percentage, and for a longer time period, than is currently compensated under the SSL Sources rate, such as 50% below the nominal wattage, and up to 6 hours per night. I also recommend that the Company explicitly take into account the municipal acquisition of management of streetlights and the conversion to LEDs in its forecasting and allocated cost of service study. Finally, I recommend that the Company commit to applying the S-05 tariff, and the SSL Sources rate in particular, in a clear and transparent manner that fully compensates the efficiency values achieved by customers through adoption of LED lights and smart control technologies.

GAS BUSINESS ENABLEMENT

Q. What are your concerns regarding the Company's Gas Business Enablement spending proposals?

A. The Company proposes a wide-ranging and expensive program of spending pursuant to an enterprise-wide (National Grid U.S.) program that it calls "Gas Business Enablement" ("GBE"). I find that the proposed spending is inadequately justified and therefore unreasonable. My chief concern is that the Company is proposing to "gold-plate" its gas business operations in an unjustified effort to grow its rate base without adequately demonstrating that the benefits of the spending outweigh the costs.

Q. What does the Company propose under its GBE proposals?

A. The Company asserts that this program is "at its heart . . . aimed at improving the customer experience to meet the relatively high customer expectations that exist in today's operating environment, and which are simply not possible to meet using today's operating processes."[71] The Company asserts that the spending "will improve the Company's ability to provide safe, reliable, and cost-effective delivery of natural gas to its customers."[72] The Rhode Island share of the Company's $478.3 million plan is $43.5 million, relating to spending by Narragansett Gas ($38.5 million) and Narragansett Electric ($5 million).[73] The total revenue requirements for FY 2019 through FY 2021 are proposed at $13.6 million for Gas, and $1.8 million for Electric.[74] Essentially, the Company argues that the Commission must approve spending and rate recovery of the Rhode Island share of the enterprise-wide spending, because to do so would be less expensive than the cost of improvements on a state-by-state basis.[75] Over the next several years, the bill to Rhode Island customers proposed by the Company is $17.3 million dollars, as reflected in Figure 7, below.

Figure 7: Proposed Expenses to be Charged to Rhode Island Customers, Gas Enablement Program 2017-2021.[76]

Fiscal Year (FY) Period	Revenue Requirements for Capital Costs	O&M (Gas)	Estimated Total Annual Expense Charged to the Company
FY 2017		$1,176,955	$1,176,955
FY 2018	$66,415 (Gas) $26,083 (Electric)	$1,284,801	$1,315,216
FY 2019	$1,830,808 (Gas) $472,309 (Electric)	$3,943,863	$5,774,671
FY 2020	$2,416,340 (Gas) $634,322 (Electric)	$2,282,372	$4,698,712
FY 2021	$3,223,587 (Gas) $578,931 (Electric)	$1,128,389	$4,351,976
	TOTAL ANNUAL EXPENSE – (2017-2021)		$17,317,530

[71] Prefiled testimony of Company witnesses Johnston & Connolly, at pp. 6-7 (Book 7).
[72] *Id.* at p. 7.
[73] *Id.* at p. 8.
[74] Prefiled testimony of Company witness Melissa A. Little, at Sched. MAL-36.
[75] *Id.* at pp. 9-11.
[76] *Id.*at 9.

Q. How does the Company propose to recover the costs associated with its GBE program proposals?

A. The Company revealed as a result of discovery that it proposes to allocate GBE program costs on a per-customer basis.[77] This proposal is patently unfair and inconsistent with sound rate making principles. The costs associated with the proposed GBE are not related to the cost to connect customers to gas service or exclusively, or even primarily associated with customer count.

Q. Why does the Company believe that the GBE program investments are required?

A. The Company basically asserts that its current systems and processes are inefficient, difficult, and rely on many manual processes that could be automated. The Company asserts that "there is risk involved in continuing to rely on the current processes and sub-systems to support safe and reliable operations while meeting customer expectations."[78]

Q. Does the Company provide any quantified, empirical evidence to support its assertion that processes are more expensive and less efficient than they would be after spending the GBE program amounts?

A. No. The Company does not offer a Benefit-Cost Analysis to support its proposal specific to Rhode Island or for the GBE program as a whole.

Q. Does the Company offer any quantitative analysis to support its proposal?

A. The only analysis offered by the Company in support its GBE program, which was provided in response to a discovery request, is that the program would be more expensive to pursue on a state-by-state basis than on an enterprise wide basis. [79] Of course, evidence

[77] *See* Company response to NERI 16-2.
[78] *Id.*at 13.
[79] Company response to DIV 3-64.

that the program would be less expensive on an enterprise-wide basis tells us nothing about whether the program is reasonable in the first place and demonstrably more cost effective than smaller, more targeted initiatives.

Q. Does the Company quantify the risk associated with relying on the existing systems in Rhode Island, or the benefits of the GBE program investments in reducing or eliminating these risks?

A. No.

Q. Does the Company provide evidence to support its assertion that the Customer Enablement component of the GBE program is grounded in empirical research or a thorough characterization of customer expectation regarding gas utility service?

A. No. The Company offers several arguments about the extent to which customers expect on-line, real-time opportunities to interact with service providers, such as through web portals and mobile device applications,[80] but offers no customer research data or empirical evidence that these expectations relating to "ease and convenience"[81] extend to customers' relationship with their gas supply utility.

Q. Does the Company specifically identify problems or potential problems associated with gas business services in Rhode Island?

A. No. The Company asserts that it has a system-wide problem with its gas business in the U.S. and that "it is in an unsustainable position in terms of meeting operating and customer-service requirements with current, legacy systems within the rapidly changing external environment."[82] The Company identifies no Rhode Island-specific problems,

[80] *Id.* at 13-15.
[81] *Id.* at 14.
[82] *Id.* at 15.

does not explain how it got itself into an "unsustainable position," why rate payers should be responsible for addressing the dilemma, or why its proposed GBE program is a reasonable, optimal, and cost-effective solution to the situation it is in.

Q. Does the Company establish an adequate foundation for its proposals based on regulatory requirements?

A. The Company asserts that its "[a]ging, disparate, and duplicative systems hamper the Company's ability to demonstrate compliance and manage performance.[83] However, the Company offers no specifics, no quantification, and no Benefit-Cost Analysis to support its GBE program proposal as a regulatory compliance program.[84] The Company does cite recent events in other states as drivers for "increasing requirements,"[85] but offers no specifics connections between these requirements and the GBE program proposal.

Q. How does the Company characterize evolving customer expectations?

A. The Company implies that because a customer can use their mobile device to order an Uber ride or buy groceries, they have the same expectation regarding ascertaining the purpose of a gas utility truck sighted in their neighborhood. The Company therefore argues that the GBE program is necessary to meet customer expectations.[86]

Q. Does the Company quantify the benefits of its proposed work process improvements?

---

[83] *Id.* at 17.
[84] *See* Company response to NERI 16-1, asserting that no Benefit-Cost Analysis was performed because the only alternative to the GBE program is a "run to failure." "National Grid has not tried to value the cost of catastrophic failure, but rather has recognized the critical need for these assets to be replaced and has undertaken the efforts necessary to achieve this outcome."
[85] *Id.* at 18.
[86] *Id.* at 19-20.

A. No. The Company describes but does not quantify the potential benefits of its proposed "key work-process improvements."[87]

Q. Does the Company offer any performance metrics to underpin its assertion that it will prudently manage and govern the GBE program?

A. The Company provides an extensive narrative description of the ways in which it proposes to ensure that the GBE program would be prudently managed and governed.[88] The Company provides no quantitative or qualitative metrics associated with these plans.[89]

Q. Does the Company quantify or empirically demonstrate the changes that would result from implementation of the proposed GBE program?

A. No. While the Company provides a brief narrative description of "Before and After Scenarios" in support of its proposal,[90] it provides no quantitative analysis to support an evaluation of those scenarios. It does cite one statistic—that National Grid responds to "approximately 2,300 service appointments *per day* across its three operating jurisdictions."[91] The Company does not relate this statistic to Rhode Island specifically.

Q. Based on your review of the Company's GBE program proposal, what do you conclude?

A. The Company's GBE proposal sounds good, and if one accepts the premise that current gas service is unsustainable, it may be an idea worth explaining. But the Company's GBE proposal is simply not ready for regulatory and rate making approval by the Commission.

---

[87] *Id.* at 23.
[88] *Id.* at 24-35.
[89] *See* Company response to NERI 5-5.
[90] *Id.* at 35-42.
[91] *Id.* at 39.

The Company's GBE program proposal is massively expensive, and should be supported by specific empirical evaluation of the benefits and costs of the program and its specific elements.

Q. What do you recommend based on your conclusions?

A. I recommend that the Commission disapprove any recovery in rates for the GBE program at this time, including in the test year. I also recommend that the Commission direct the Company to provide quantitative analysis to support its proposals and to document the benefits associated with the costs it proposes as a condition of any subsequent filing seeking rate recovery of costs associated with the GBE program. The Commission should also require the Company to seek recovery of prudent and authorized costs through a volumetric charge.

TRADE ASSOCIATION DUES

Q. What are your concerns regarding trade association dues?

A. This testimony addresses the Company's "above-the-line" trade association dues—*i.e.*, dues recovered from ratepayers that, unbeknownst to most ratepayers, may be subsidizing advocacy with which they disagree and that is contrary to their interests. While the shareholders of the Company pay trade association lobbying expenses (the "below-the-line" portion of dues), the remainder of the dues are categorized as an operating expense in the Company's rate request.[92] Groups such as the Edison Electric Institute ("EEI") and American Gas Association ("AGA"), which receive a majority of their revenue from utility membership dues, are highly political in nature and promote policies that are not always in the best interests of ratepayers. To protect the interests of ratepayers, and to

[92] *See* Company Responses to NERI 9-1 and NERI 9-4.

ensure just and reasonable rates, I recommend that the total amount of requested revenue requirement of $122,467.80 in the electric rate case and $91,961.58 in the gas rate case be disallowed.[93] These expenses must be disallowed because the Company has (1) failed to provide data supporting the allocated share of EEI and AGA dues that it seeks to recover from customers, and (2) failed to demonstrate that the costs associated with EEI and AGA membership dues are limited to activities that benefit ratepayers and therefore are just and reasonable.

Q. What is EEI, and what services does the trade association provide to its members?

A. EEI is a trade association with a large operating budget ($90 million in 2015) that represents U.S. investor-owned electric companies in all 50 states.[94] EEI describes its mission as providing public policy leadership, industry data, business intelligence, conferences and forums, and products and services to the utility industry.[95] EEI also provides a Mutual Assistance Program in which member utilities can access assistance during storms to restore power to affected customers.[96] Most of EEI's work involves promoting its utility members' policy agenda and bottom-line through political action and legal intervention.[97]

Q. What is AGA and what services does the trade association provide for its members?

A. AGA is a trade association that represents more than 200 natural gas supply companies in the United States. AGA supports the use and production of natural gas through regulatory

---

[93] *See* Company Response to PUC 1-45.

[94] David Anderson et al., Energy & Policy Inst. ("EPI"), Paying for Utility Politics 4 (2017) ("EPI, *Paying for Utility Politics*"), *available at* http://www.energyandpolicy.org/wp-content/uploads/2017/05/Ratepayers-funding-Edison-Electric-Institute-and-other-organizations.pdf.

[95] *See* EEI, *About EEI*, http://www.eei.org/about/Pages/default.aspx (last visited April 4, 2018).

[96] *See* EEI, *Mutual Assistance*, http://www.eei.org/issuesandpolicy/electricreliability/mutualassistance/ (last visited April 4, 2018).

[97] *See* EPI, *Paying for Utility Politics* at 4.

and policy intervention, development assistance, exchange of information, and conferences and workshops.[98] AGA advocates for the increased development of pipeline infrastructure.[99] AGA also is credited with positioning natural gas as a "bridge fuel," allowing for natural gas to be publicly viewed as part of the solution to climate change.[100]

Q. Is the Company a member of EEI or AGA?

A. Yes, the Company is a member of both EEI and AGA.[101]

Q. Does the Company pay its membership dues directly to EEI and AGA?

A. No. The dues are paid by the parent company, National Grid USA, which then allocates Narragansett Electric Company's share of dues to the Company.

Q. Does the Company seek to recover any portion of its allocated share of EEI and AGA membership dues from ratepayers?

A. Yes, the Company seeks to recover EEI and AGA membership dues from ratepayers, excluding the amounts the EEI and AGA define as lobbying.[102] In the instant proceeding, the Company seeks to recover $122,467.80 in EEI dues and $91,961.58 in AGA dues.[103]

Q. How does the Company determine what portion of the EEI and AGA dues to recover from ratepayers and what portion of the dues to recover from shareholders?

---

[98] *See* AGA, *Our Mission*, https://www.aga.org/about/our-mission (last visited April 4, 2018).
[99] *See* AGA, 2017 Playbook, *Natural Gas: Moving Our National Forward* at 24–27, http://playbook.aga.org (last visited April 4, 2018).
[100] *See* Jeff Share, *Dave McCurdy Brings Strong Credentials to AGA* (Dec. 2011), https://pgjonline.com/2011/12/01/dave-mccurdy-brings-strong-credentials-to-aga/.
[101] Company Response to PUC 1-45.
[102] *See* Company Responses to NERI 9-1 and NERI 9-4.
[103] *See* Company Response PUC 1-45.

A. The Company apportions expense according to invoices sent by EEI or AGA, which identify the below-the-line lobbying expenses and above-the-line non-lobbying expenses.[104]

Q. What portion of EEI's or AGA's budget is allocated toward lobbying activity as compared with other activities?

A. The National Association of Regulatory Utility Commissioners ("NARUC") conducted its last annual audit of EEI data in 2005. In that audit, more than 55% of EEI's expenditures went to the following categories: legislative advocacy; regulatory advocacy; and legislative and regulatory policy research.[105] We do not know whether EEI treated all of that spending as lobbying. The Company has not submitted a more recent audit in this proceeding. However, the Company does acknowledge that AGA dues paid in 2013, 2014, and 2015, were incorrectly recorded in total as operating expenses.[106]

Q. Why is it important to know how EEI and AGA treat expenditures?

A. Reliable data on EEI and AGA spending activity is necessary for reasonable allocations of expenses between lobbying and non-lobbying activity. Absence of that data presents a significant challenge for stakeholders, ratepayers, and regulatory authorities who seek to protect ratepayers from funding lobbying and any non-lobbying advocacy that may not be in their best interest. For example, the expense column under AGA's 2016 Consolidated Statement of Activities lists various categories that may be related to lobbying advocacy,

---

[104] *See* Company Responses to NERI 9-2 and NERI 9-5.
[105] *See* EPI, *Paying for Utility Politics* at 33 tbl.11.
[106] *See* Company Response to NERI 9-5.

including federal and state government relations, policy, communications, and general counsel and federal regulatory affairs.[107] These expenses total over $12 million.[108]

Q. Why is it important to determine what activities and policies the EEI and AGA ratepayer-funded dues support?

A. Rhode Island energy policy is committed to a clean, distributed, affordable energy future,[109] while EEI and AGA advocacy and policy positions have been demonstrably inimical to the type of clean energy goals Rhode Island hopes to achieve. The development of more distributed renewable energy assets and energy efficiency programs, coupled with a reduction in the expansion of fossil fuels and GHG emissions, provide direct and quantifiable benefits to ratepayers throughout the State.

Q. What dues-funded EEI and AGA activities are in the interest of Rhode Island ratepayers?

A. Examples of association activities clearly in the interests of ratepayers include: EEI and AGA sponsored workforce education and training modules, knowledge campaigns centered around electrical and gas safety, and EEI's Mutual Assistance Program that combines utility resources during extreme weather to restore power to customers.

Q. So, what is the problem with above-the-line trade association dues?

The EEI and AGA act as advocacy organizations in supporting a policy agenda contrary to a many ratepayers' interests or personal beliefs, and the policies of the State of Rhode Island. In one example, over the period of 2008 to 2015, EEI donated $142,667 to the American Legislative Exchange Council ("ALEC"), of which AGA is a member as

---

[107] *See* NERI 9-8-2, page 5 of 6.
[108] Id.
[109] *See* Governor's 1000 by '20 Clean Eenrgy Goal, http://www.energy.ri.gov/renewable-energy/governor-clean-energy-goal.php (last visited April 4, 2018).

well.[110] ALEC, a politically conservative 501(c)(3) organization, provides state legislators with "model bills" to oppose renewable energy standards and overturn laws that reduce carbon dioxide emissions.[111]

Q. Are you recommending that the Company not be allowed to indirectly fund ALEC or other anti-renewable energy advocacy organizations through its contributions to EEI and AGA member dues?

A. No. I accept that the Company may decide that it is in the best interests of shareholders to join in these agendas. My testimony is that ratepayers should not be required to support these organizations, directly or indirectly, through EEI and AGA dues, and that the Company must produce sufficient and competent evidence that any dues payments that it seeks to recover from ratepayers through the revenue requirement do not fund these activities.

Q. What other issues has EEI supported that conflict with ratepayers' interests?

A. EEI maintains an ongoing effort to fuel doubt about climate science and oppose limits on carbon emissions.[112] EEI advances this goal primarily by funding special interest groups like the Utility Air Regulatory Group ("UARG") and ALEC.[113] UARG recently submitted comments to the Trump Administration encouraging the repeal and replacement of the Clean Power Plan, broadly arguing against EPA's regulations

---

[110] EPI, *Paying For Utility Politics*, at 17.

[111] *See* Suzanne Goldenberg & Ed Pilkington, *ALEC Calls for Penalties on 'Freerider' Homeowners in Assault on Clean Energy*, The Guardian, Dec. 4, 2013, https://www.theguardian.com/world/2013/dec/04/alec-freerider-homeowners-assault-clean-energy.

[112] *See* EPI, Utilities Knew: Documenting Electric Utilities' Early Knowledge and Ongoing Deception on Climate Change from 1968–2017 at 7 (2017) ("EPI, *Utilities Knew*"), *available at* www.energyandpolicy.org.

[113] In a 2015 case before the Indiana Utility Regulatory Commission ("IURC"), testimony revealed that $173,612 of EEI annual dues were paid to UARG. *See* Verified Direct Testimony of Derric J. Isensee, Att. 6-B, at 37, Cause No. 44688 (IURC Oct. 1, 2015), https://assets.documentcloud.org/documents/3111258/Northern-Indiana-Public-Service-Company-Dues.pdf.

requiring lower carbon emissions from utilities.[114] In contrast, the State of Rhode Island Attorney General, representing the people of Rhode Island, has joined a coalition of AGs, states and cities in support of the Clean Power Plan.[115] Rhode Island is also joining an alliance of states committed to the Paris Agreement and pledging to reduce GHG emissions.[116]

EEI also has directly challenged state programs for rooftop solar and distributed energy resources ("DER"). In 2014, EEI filed comments to the Arizona Corporation Commission to challenge Arizona's net-metering policy.[117] EEI advocated for a change in the value of distributed resources, arguing, among other things, that "grid security and reliability should not be considered in rates," that" environmental and social externalities should not be included in [distributed generation ("DG")] rates," and that "DG systems should not be compensated directly for reducing market prices."[118] To support its position, the EEI ran $500,000 worth of television ads attacking solar customers.[119]

Q. What issues has AGA supported that conflict with ratepayers' interests?

[114] *See* Letter from Andrea B. Field, Counsel, UARG, to Samantha K. Dravis, EPA, 5 (May 12, 2017), *submitted in* EPA, Docket ID EPA-HQ-OA-2017-0190-0042, *available at* https://www.regulations.gov/contentStreamer?documentId=EPA-HQ-OA-2017-0190-40140&attachmentNumber=1&contentType=pdf.
[115] *See* Press Release, New York State Attorney General Eric T. Schniederman, A.G. Schneiderman Leads Coalition of States and Localities in Opposing Pres. Trump's Efforts to Dismantle the Clean Power Plan (Mar. 28, 2017), https://ag.ny.gov/press-release/ag-schneiderman-leads-coalition-states-and-localities-opposing-pres-trumps-efforts.
[116] *See,* "Three New England States Join R.I. in Pledge to Combat Climate Change," at http://www.providencejournal.com/news/20170602/three-new-england-states-join-ri-in-pledge-to-combat-climate-change (last visited April 4, 2018).
[117] Comments of the Edison Electric Institute, *Value & Cost of Distributed Generation (Including Net Metering)*, Docket No. E-00000J-14-0023 (Ariz. Corp. Comm'n Feb. 14, 2014), *available at* http://docket.images.azcc.gov/0000151239.pdf (formatting altered).
[118] *Id.* at 9–10.
[119] *See* Adam Browning, *Edison Electric Institute Really Does Not Want You to Go Solar*, Greentech Media, Feb. 28, 2014, https://www.greentechmedia.com/articles/read/in-rare-public-filing-edison-institute-downplays-value-of-solar-for-arizon; *see also* EEITV, *We All Rely on the Electric Grid*, YouTube (Nov. 3, 2013), https://www.youtube.com/watch?v=Ut1_PosSLtk.

A. AGA maintains an ongoing funding effort to support the growth and promote the use of natural gas in the United States.[120] Although natural gas emits fewer GHGs during the combustion process compared with other fossil fuels like coal and oil, a significant amount of methane is released throughout the natural gas life cycle, from extraction to transportation and distribution. As a result, natural gas has a significant GHG impact. In addition, natural gas historically has been characterized by volatile commodity prices, and given this volatility, expanding gas service can have a direct, negative impact on ratepayers. Furthermore, natural gas is not guaranteed to remain cheap for the useful life of the natural gas infrastructure investments that AGA supports. Taken together, natural gas expansion is demonstrably not in the interest of ratepayers.

Q. What other issues contrary to ratepayer interests has AGA supported?

A. AGA funded and launched Your Energy, which is a public relations campaign masquerading as a grassroots effort to combat genuinely local opposition to pipelines and gas in Virginia.[121] In addition, AGA and EEI are members of the Utility Solid Waste Activities Group ("USWAG"). USWAG addresses solid and hazardous waste issues on behalf of utilities and trade associations, while pursuing a litigious agenda against environmental rules and regulations that do not benefit a utility's bottom line. For example, the EPA Coal Combustion Residuals Rule places basic requirements on the maintenance, cleanup, and groundwater monitoring of coal ash waste.[122] USWAG is

---

[120] *See* Jennifer Yachnin, *American Gas Association Seeking to Spread Its Influence Well Beyond the Beltway*, E&E Daily, Dec. 9, 2011, https://www.eenews.net/stories/1059957439.
[121] Alexander C. Kaufman, *Natural Gas Industry Brings a Fake Grassroots Movement Group to Eastern Pipeline Fights*, HuffPost, June 19 2017 (updated), http://www.huffingtonpost.com/entry/natural-gas-pipeline-your-energy-virginia_us_593afeb1e4b0240268793e8d.
[122] *See* Disposal of Coal Combustion Residuals from Electric Utilities, 80 Fed. Reg. 21,301 (Apr. 17, 2015).

petitioning the EPA for a stay of the rule, calling it "ill-conceived and burdensome."[123] This action is likely to harm a ratepayer through the reduced regulatory oversight and increased risk of environmental and public health hazards.

Q. Do any third-party regulatory organizations conduct oversight of utility EEI and AGA dues?

A. No, there is no regulatory oversight of the allocation of trade association membership dues today. From the 1980s to the early 2000s, NARUC conducted annual audits of trade association financial records through the Committee on Utility Oversight.[124] The audits persuaded NARUC regulators to direct utilities to collect a smaller portion of their EEI and AGA dues from ratepayers.[125] Once the Committee disbanded in the year 2005, NARUC stopped auditing expenditure data. Recently, utilities have been seeking lower than usual amounts from shareholders: Georgia Power proposed 29% of EEI dues as below-the-line expenses in a 2016 filing,[126] NV Energy proposed 16% in a 2015 filing,[127] and Oklahoma Gas & Electric proposed 0% in a 2016 filing.[128] Without transparency of spending data, it is difficult to fully understand how EEI and AGA spend ratepayer funds. The Commission is the best institution to address this issue in the absence of a coordinated multi-state audit like that NARUC conducted.

---

[123] *See* Lyndsey Gilpin, *As Coal Ash Rules are Challenged, Activists Worry About Long-Term Monitoring*, Southeast Energy News, June 13, 2017, http://southeastenergynews.com/2017/06/13/as-coal-ash-rules-are-challenged-activists-worry-about-long-term-monitoring/.
[124] *See* NARUC Bd. of Directors, Resolution Regarding Discontinuation of the Committee on Utility Oversight (adopted Mar. 8, 2000), *available at* http://pubs.naruc.org/pub/5398B543-2354-D714-51D3-90ACAB1DA952.
[125] *See* EPI, *Paying for Utility Politics*, at 6.
[126] *See id.* at 20.
[127] *See id.* at 24.
[128] *See id.* at 20–21; Responsive Test'y of Sharhonda Dodoo at 6 tbl.1, *In re Okla. Gas & Elec. Co.*, No. PUD 201500273 (Corp. Comm'n Okla. Mar. 21, 2016), *available at* https://www.documentcloud.org/documents/3111578-Sharhonda-Dodoo-PUD-Testimony-OGE-Dues.html#document/p6/a318911.

Q. How have other public utility commissions handled this issue?

A. While I have not conducted a comprehensive survey of all states, commissions in several states have held that the utility company bears the burden to provide evidence that establishes that proposed rate recovery of above-the-line EEI dues benefit ratepayers. In 2013, The Utility Reform Network ("TURN"), a California-based advocacy organization that represents consumers before the California Public Utilities Commission ("CPUC"), succeeded in challenging the above-the-line EEI dues allocation proposed by Pacific Gas & Electric Co. ("PG&E").[129] TURN argued that "EEI spends money on many other things that do not fit the narrow definition of lobbying" but nevertheless could impair ratepayer interests and therefore should not be funded by ratepayers.[130] Based on TURN's argument and the most recent 2005 NARUC audited data, the CPUC decided to increase the allocation of below-the-line dues from the 25% proposed by PG&E to 43.3%.[131] In a later Southern California Edison ("SCE") case, SCE proposed to recover only 24% from shareholders, while TURN requested that 100% of EEI dues be disallowed.[132] In that instance, the Administrative Law Judge ("ALJ") agreed that SCE has "not shown that it has removed all political or lobbying costs from its forecast."[133] In

[129] *See* EPI, *Paying for Utility Politics*, at 34–37.
[130] William B. Marcus, Electric Generation and Other Results of Operations Issues for Pacific Gas & Electric Co., Prepared Testimony on behalf of TURN at 68, *In re Pacific Gas & Elec. Co.*, Appl'n No. 12-11-009 (Cal. Pub. Utils. Comm'n May 17, 2013), *available at* https://assets.documentcloud.org/documents/3382426/TURN-PGE-Testimony-2014-Rate-Request.pdf.
[131] Proposed Decision Granting Compensation to The Utility Reform Network for Substantial Contribution to Decision 14-08-032 at 8, *In re Pacific Gas & Elec. Co.*, Appl'n No. 12-11-009 (Cal. Pub. Utils. Comm'n undated), *available at* https://www.documentcloud.org/documents/3239245-COMPENSATION-to-TURN-for-SUBSTANTIAL.html#document/p8/a331970.
[132] *See* EPI, *Paying for Utility Politics*, at 35–37.
[133] *Id.* at 36.

the ruling, the ALJ proposed to increase the below-the-line allocation to 47.9% from SCE's proposed 24%.[134]

In 2015, the Missouri Public Service Commission ("MO-PSC") staff presented testimony in support of disallowing all above-the-line EEI dues, stating: "Staff's recommendation to disallow the entire amount of EEI dues stems from [Union Electric Co. d/b/a Ameren Missouri's] failure to quantify these benefits between shareholders and the ratepayers."[135] MO-PSC staff noted that the MO-PSC had excluded all EEI dues in a prior proceeding on the ground that "these payments have not been shown to produce any direct benefit to the ratepayers."[136] After negotiations, the MO-PSC staff and Ameren Missouri agreed to entry of a settlement order.[137]

Q. What do you propose to ensure that ratepayers are not required to fund activities from which they receive no benefit or by which they risk being harmed?

A. The Company must provide sufficiently detailed information regarding the membership dues cost allocation as an incident to its burden of producing sufficient evidence that its requested rates are just and reasonable. This evidence must demonstrate that above-the-line dues to EEI and AGA: (1) directly benefit ratepayers and (2) do not work contrary to ratepayer interests. Due to the conflict of interest between those organizations and Rhode Island ratepayers, and in the absence of a third-party audit in the record, it is not reasonable to rely solely on an EEI or AGA invoice to support the necessary finding. The data submitted by the Company therefore is inadequate to carry the Company's burden of

[134] *See id.*
[135] Surrebuttal Test'y of Jason Kunst at 2, *In re Union Elec. Co. d/b/a Ameren Missouri*, Case No. ER-2014-0258 (MO-PSC Feb. 6, 2015) (citation omitted), *available at* https://assets.documentcloud.org/documents/3320628/MO-PSC-Surrebuttal-Testimony-Dues.pdf.
[136] *Id.* at 3 (quoting Report and Order, *In re Union Electric Company*, Case No. EC-87-114 (MO-PSC)).
[137] EPI, *Paying for Utility Politics*, at 31.

demonstrating that its rates are just and reasonable or to confirm that ratepayers are not being asked to pay for lobbying or political advocacy activities carried out by the EEI or AGA.

Q. What do you recommend that the Commission do in the face of this lack of evidence?

A. Because the Company has not provided sufficient and competent evidence to support a finding that the dues it is asking ratepayers to pay are a just and reasonable expense, I recommend that the total amount of requested revenue requirement of $122,467.80 in the electric rate case and $91,961.58 in the gas rate case be disallowed.

Q. Does this conclude your testimony?

A. Yes.