Advancing the Clean Energy Future

Acadia Center

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April 6, 2018

By US Mail and Email

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

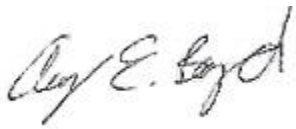
RE: Docket No. 4770

Dear Ms. Massaro:

Enclosed for filing in the above referenced docket, please find one original and nine copies of the Pre-Filed Direct Testimony of Mark LeBel on behalf of Acadia Center, and a certificate of service.

Please contact me with any questions concerning this matter. Thank you for your attention to this filing.

Sincerely,



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CC: Docket No. 4770 service list (*via email*)

CERTIFICATE OF SERVICE

I certify that on April 16, 2018, the Pre-Filed Direct Testimony of Mark LeBel on behalf of Acadia Center were served via US Mail and electronic mail on the Clerk of the Rhode Island Public Utilities Commission, and on the service list via electronic mail.

/s/ Amy E. Boyd

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Amy E. Boyd

STATE OF RHODE ISLAND
PUBLIC UTILITIES COMMISSION

IN RE: NATIONAL GRID APPLICATION TO CHANGE ELECTRIC AND GAS DISTRIBUTION REVENUE REQUIREMENTS AND ASSOCIATED RATES	))))))	DOCKET NO. 4770

PRE-FILED DIRECT TESTIMONY OF MARK LeBEL,

ON BEHALF OF ACADIA CENTER

Exhibit AC-ML-1

April 6, 2018

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I. INTRODUCTION

Rhode Island has laid out bold plans to embrace a consumer-friendly clean energy future, which includes an ambitious set of utility regulatory reforms. National Grid has filed, in this Docket No. 4770, an Investigation as to the Propriety of Proposed Tariff Changes, along with a Power Sector Transformation Plan, which was docketed in Docket 4780. Acadia Center has concerns that portions of National Grid's proposals for rate design and the return on equity may be unfair to consumers and contrary to Rhode Island policy goals. Additionally, the current procedural bifurcation of the rate case and power sector transformation proposals may need to be adjusted by the Public Utilities Commission ("PUC") to enable the transformation contemplated in Order 22851 of Docket 4600.

II. QUALIFICATIONS

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

A. My name is Mark LeBel. I am a Staff Attorney for Acadia Center, located at 31 Milk Street, Suite 501, Boston, MA 02109.

Q. Please tell me more about Acadia Center.

A. Acadia Center is a non-profit, research and advocacy organization committed to advancing the clean energy future in the Northeast. Acadia Center is at the forefront of efforts to build clean, low carbon and consumer friendly economies, and has offices in cities throughout the Northeast, including Providence. Acadia Center's approach is characterized by reliable information, comprehensive advocacy, and problem solving through innovation and collaboration. Collectively, Acadia Center's staff has several decades of experience on the impact of utility rate design on consumer adoption of energy efficiency and clean energy technologies and the ability of consumers to control their energy bills. Acadia Center has been active in Rhode Island and other northeastern states in dockets and proceedings concerning grid modernization and utility business model reform, and, in 2015, published UtilityVision: Reforming the Energy System to Work for Consumers and the Environment. UtilityVision outlines specific steps needed to modernize the power grid, including reforms to the utility business model, grid planning,

and rate-making that will guide infrastructure investments to a consumer-focused and technology-friendly energy system.

Q. Please summarize your work experience and educational background.

A. I have been employed by Acadia Center since 2013. In my current position, I have participated in policy advocacy on a wide range of topics, spanning clean transportation, grid modernization and utility reform, renewable energy, and energy efficiency. More specifically, I have led Acadia Center's efforts around vehicle electrification since 2014 and around electricity rate design and compensation for distributed energy resources (DER) since 2015. Since the fall of 2017, I have co-lead Acadia Center's broader work around grid modernization and utility reform across the region. Based on my work on vehicle electrification, I was appointed to be a member of the Massachusetts Zero Emission Vehicle Commission in 2015 and I chaired the subcommittee on Infrastructure, Planning & Regulatory Issues as a part of the Rhode Island Zero Emission Vehicle Working Group.

Prior to joining Acadia Center, I worked at Connecticut Fund for the Environment on state-level energy and climate policy in 2012 and 2013. From 2007 to 2009, I worked as an analyst at NERA Economic Consulting, performing economic analysis of energy and environmental policies.

I received a J.D. from New York University in 2012. My classwork, extracurriculars, and employment during law school focused on the law and economics of policies related to energy and the environment, including my published note on sulfur dioxide trading and the Clean Air Interstate Rule. I received my bachelor's degree in Applied Mathematics, with a focus in economics, from Harvard College in 2007. A copy of my resume is appended to this testimony as Exhibit AC-ML-2.

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

A. No.

Q. Have you provided expert testimony in other jurisdictions?

A. Yes, I have provided expert testimony addressing rate design and electric vehicle charging proposals in Eversource's recent rate case in Massachusetts, D.P.U. 17-05. I have also provided expert testimony on National Grid's electric vehicle market

development proposal in Massachusetts, D.P.U. 17-13, and on rate design issues in National Grid's recent rate case in New York, Case 17-E-0238.

Q. Have you participated in other capacities in proceedings at the Rhode Island PUC?

A. Yes. I served as counsel for Acadia Center in Docket 4568 on electricity rate design and participated in Docket 4600 on rate design issues.

III. PURPOSE AND OVERVIEW OF TESTIMONY

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to describe how our energy and electric systems are changing; to lay out Acadia Center's recommendations for further reforms needed to fully realize the potential benefits of a modern energy system, including consideration of reforms to utility revenue in conjunction with performance incentives; to discuss relevant principles of rate design and rate reform; to describe Acadia Center's vision for rate design and distributed energy resource (DER) compensation in the short-, medium-, and long-terms; to review National Grid's rate design proposals; and to provide recommendations on those issues. Specifically, my testimony addresses three different pieces of National Grid's proposals: (1) return on equity, including the need to consider it in conjunction with performance incentive mechanisms and grid modernization improvements currently docketed in Docket 4780, (2) fixed monthly customer charges, and (3) the need for opt-in time of use rates in the near-term.

Q. Please summarize your conclusions regarding National Grid's proposals for return on equity.

A. National Grid's proposed return on equity is likely too high. First, National Grid's request for a 10.1% return on equity is significantly higher than recent returns approved in other jurisdictions, including the 9% return for National Grid's New York affiliate. Second, high returns on equity are contrary to the objectives of RI state law and the Power Sector Transformation process. High ROE perpetuates incentives for utilities to make as many capital investments as possible, and overlook non-infrastructure solutions, such as distributed energy resources, which can be cheaper and cleaner. As the state's "Rhode Island Power Sector Transformation Phase One Report to Governor Gina M.

Raimondo" (hereinafter "PST Report") concludes, "we recommend shifting the traditional utility business model away from a system that rewards the utility for investment without regard to outcomes towards one that relies more upon performance-based compensation…" PST Report[1] at 9). Accordingly, return on equity, as well as other traditional utility compensation, should be reduced proportionally to account for the performance-based compensation that is being added through National Grid's Power Sector Transformation proposal ("National Grid's proposed PST") in Docket 4780.

Q. How does this implicate topics pending in Docket 4780?

A. Chair Curran determined that National Grid's proposed PST, filed concurrently with and originally docketed in this rate case, should be assigned to its own docket to accommodate different testimony filing deadlines. However, this procedural bifurcation should not dictate the outcome of substantive issues or override Rhode Island's larger policy goals. As the performance incentive mechanisms and recovery for grid modernization improvements filed in the proposed PST should impact the returns that National Grid earns otherwise, it is important to consider such issues in this docket.

Q. Please summarize your conclusions regarding National Grid's proposals for monthly customer charges.

A. High monthly customer charges limit customer control of bills and impact incentives for energy efficiency investment and distributed generation. High customer charges also shift cost recovery from large consumers of electricity to small consumers of electricity, who are often low-income. Customer charges should be capped at properly calculated customer-related unit costs and may be lower based on public policy principles. There are three categories of potential issues with respect to National Grid's proposed monthly customer charges. First, it is inappropriate to include any demand-related costs in the customer charge. Second, National Grid applies an over-inclusive definition, which increases its estimate of customer-related costs. Finally, these calculations, including the overall revenue requirements and full allocated cost of service study, need to be updated to reflect significant changes in the federal tax rates due to the passage of H.R.1, The Tax

[1] Available at: http://www.ripuc.org/utilityinfo/electric/PST%20Report_Nov_8.pdf

Cuts & Jobs Act.[2] Given these issues, the present residential customer charge of $5 is likely an appropriate level going forward.

Q. Please summarize your conclusions regarding National Grid's proposals for time varying rates.

A. Given that National Grid proposes to rollout opt-out time-varying rates beginning in 2023, it will be at least five years before ratepayers are able to take advantage such rates. This approach will miss significant opportunities in the meantime to have a meaningful customer response through load shifting, earn more hands-on experience for Rhode Island customers, create a market for energy management technologies, and learn lessons for the larger rollout of opt-out rates. As such, the PUC should order National Grid to make opt-in time of use rates available for residential and small business rate classes as soon as possible, with significant outreach, education, and customer tools to achieve a reasonable adoption rate.

IV. THE CHANGING ENERGY SYSTEM AND NECESSARY REFORMS

Q. What are the emerging trends in the energy system that are relevant to this proceeding?

A. Electric customers increasingly have access to new, lower-cost technologies that enable clean, local generation and greater customer engagement. Customers are no longer just passive consumers of electricity and have even greater potential to help shape a cleaner, lower cost energy system through their investment decisions and behaviors. To fully realize this potential, updated regulations are needed to align the utility's financial interests with the interests of consumers and a sustainable energy system. Rhode Island recently explored how policy and regulatory change can enable utilities to become full partners, remove barriers to the deployment of clean energy resources, and advance consumer choice and control through the Power Sector Transformation process and Docket 4600. Such changes are needed to accelerate the pace at which the energy system

[2] The Company has reportedly updated its allocated cost of service study to reflect the changes in federal tax code as of April 5th, however Acadia Center has not yet been able to review these documents.

shifts to a more decentralized model with significant levels of local, distributed energy resources.

Q. How can energy efficiency and distributed solar PV benefit consumers and the grid?

A. Investing in clean, local energy resources like energy efficiency and distributed solar PV helps avoid expensive distribution, transmission, and large-scale generation investments, and provides economic benefits, including good local jobs. It is well-documented that energy efficiency investments have allowed the region to defer and potentially avoid major transmission upgrades. "Accounting for Big Energy Efficiency in RTO Plans and Forecasts: Keeping the Lights on While Avoiding Major Supply Investments," provides a summary of transmission projects deferred due to energy efficiency in New England. I submit this document as Exhibit AC-ML-3.

Similarly, the Tiverton/Little Compton pilot project in Rhode Island, the Brooklyn/Queens Demand Management Project in New York, and the Boothbay Smart Grid Reliability Project in Maine are real world examples of local clean energy resources deferring or avoiding upgrades to the distribution grid. There are additional examples from California and New Jersey in which distributed generation has deferred or avoided, or is predicted to defer or avoid, distribution or transmission system investments.

Q. How will ratepayers, citizens, and states benefit from the changing energy system?

A. In addition to empowering consumers and communities, the transition to a modern, low-carbon energy system will generate significant public health, environmental, and economic benefits. Acadia Center assessed the greenhouse gas (GHG) emissions reduction potential from transitioning to a low-carbon energy system, and the results are presented in "EnergyVision: A Pathway to a Modern, Sustainable, Low Carbon Economic and Environmental Future."[3] The analysis shows that if the Northeast were to electrify all passenger vehicles and homes heated with fossil fuels, GHG emissions from these sources would be cut in half. By also maximizing energy efficiency and deploying new technologies and renewable resources, the region can achieve long-term GHG emissions reductions targets of 80% below 1990 levels by 2050.

[3] EnergyVision available at https://acadiacenter.org/document/energyvision/.

Q. How can Rhode Island's policies and regulations put it on a path for path for such a future?

A. Acadia Center's EnergyVision 2030 describes in detail how seven Northeast states can be on a pathway towards a reliable, consumer-oriented clean energy future that meets a goal to reduce climate pollution at least 45% from 1990 levels by 2030.[4] The Resilient Rhode Island Act sets targets to reduce climate pollution 45% from 1990 levels by 2035 on the way to an 80% reduction from 1990 levels by 2050. Using a data-driven approach, EnergyVision 2030 sets technology-specific targets in four key clean energy markets—grid modernization, electric generation, buildings, and transportation—and proposes supporting policies to achieve those goals.

Acadia Center concludes, in its Rhode Island-specific Progress Report, that while Rhode Island has ambitious renewable energy and greenhouse gas reduction goals and continues to be a regional and national clean energy leader in some areas, to build a low-carbon energy system, the state must excel across all policy areas.[5] To reach EnergyVision 2030 goals, the state should strengthen efforts to modernize the grid through current regulatory proceedings and proposed legislation; expand the Renewable Portfolio Standard and eliminate barriers to adoption of solar PV; continue to adopt all cost-effective energy efficiency and increase support for switching to heat pumps; and continue to incentivize and remove barriers to purchasing and using electric vehicles. If Rhode Island follows these policy recommendations, it will be on its way to a clean energy future.

V. UTILITY BUSINESS MODEL REFORMS NEEDED FOR RHODE ISLAND

Q. How does the current utility revenue model inhibit the transition to a modern, distributed energy grid?

A. A common way for utilities to earn revenue is by making capital investments on which the utility earns a specified rate of return set by regulators. This system gives utilities incentives to build or upgrade traditional infrastructure projects. This model is increasingly at odds with new technologies that can optimize the energy system and with

[4] EnergyVision 2030 available at: http://2030.acadiacenter.org/
[5] Rhode Island Progress Report available at: http://2030.acadiacenter.org/wp-content/uploads/2018/02/Acadia-Center_EnergyVision2030_RI-Target-Summary_20180130.pdf

public policy goals to increase energy efficiency and consumer adoption of distributed energy technologies. As noted in the Power Sector Transformation report, there are five key ways in which the traditional regulatory model's emphasis on utilities earning return on investments based on the cumulative depreciated cost of the prudent capital investments inhibits reforms. The first is creating a "capital bias" for a utility to deploy capital-intensive solutions, rather than seeking more efficient solutions that can manage system efficiency, or the ratio of peak to average demand. The second is inhibiting a utility from innovating by making it both reluctant to invest in innovative technologies for fear the investment might not be deemed prudent, and reluctant to remove technologically obsolete systems and that require a financial loss for the un-depreciated portion. One-year rate cases also provide a disincentive for a utility to incur non-capital expenses in one year that only yield savings in later years. Third, distributed energy resources require bi-directional energy flow, which can be poorly supported by both the grid infrastructure and by the rate structure. Fourth, although a modernized electric system will strongly rely on data connectivity and robust networks, a utility's "capital bias" may inhibit it from undertaking the investment in software and cloud services and developing the organizational structure and capabilities needed to undertake the information-oriented functions that will be key to future system savings. Finally, since a utility neither benefits nor is penalized as customers' electricity supply costs increase, it has no direct incentive to lower that portion of ratepayers' bills by maximizing integration of DER, even if that is consistent with the state's Least-Cost-Procurement statute and in the public interest.

Q. Has Acadia Center explored how to reform utility regulation to realize the benefits of a modern, low-carbon energy system?

A. In February 2015, Acadia Center released "UtilityVision," a framework for reforms to utility regulation to move towards a fully integrated, flexible, and low carbon electric grid that empowers and protects consumers. I submit this document as Exhibit AC-ML-4. The three categories of reforms are: (1) comprehensive, proactive, and coordinated planning for the electric grid; (2) updated roles for regulators, utilities, and stakeholders; and (3) fair pricing and consumer protection for all.

Q. Does UtilityVision offer recommendations for how to align utility incentives with consumer and environmental goals?

A. Yes. Because reforms to the utility business model are needed to enable utilities to be full partners in achieving a state's consumer and environmental goals, UtilityVision offers several high-level recommendations for steps that regulators can take to reward utilities for achieving energy efficiency and clean energy goals, minimizing the cost of the grid, and providing choices, opportunities, and control to consumers. First, states should implement full revenue decoupling to reduce a utility's financial disincentive to invest in energy efficiency, distributed generation, or other initiatives that reduce consumption. UtilityVision recognizes that decoupling only partially addresses the utility's disincentive to promote these initiatives, and further reforms are necessary to encourage full and timely implementation of policies to achieve a state's consumer and environmental goals. The next recommendation is that comprehensive, multi-year grid plans inform the amount of future revenue a utility is allowed to earn. States can also adopt performance incentive mechanisms and standards to motivate utilities to advance priorities such as system efficiency, grid enhancements, distributed generation, energy efficiency, and other consumer and environmental goals. By increasing the portion of revenue requirements recovered through performance incentives, while reducing the portion of revenue that is linked to the rate base, performance incentive mechanisms help shift the financial incentive towards achieving performance goals. The utility must still be provided a reasonable opportunity for a fair rate of return on traditionally regulated capital investments. UtilityVision also recommends that regulators clarify how new technologies and innovative utility investments interact with the criteria that determine whether the utility can recover its costs and returns.

Q. Are there other recommendations on reforming the utility business model that should be noted here?

A. In "The Old Order Changeth: Rewarding Utilities for Performance, Not Capital Investment," Scudder Parker from the Vermont Energy Investment Corporation and Jim Lazar from the Regulatory Assistance Project describe a potential way to transition from rate-of-return regulation to direct performance regulation. The authors identify three tiers

of utility performance incentives and offer a phased approach to move from a system based on a rate of return on equity and recovery of allowed costs, with attainable adders for specified objectives to long-range performance incentives tied to a major portion of future performance reward. I submit this paper as Exhibit AC-ML-5.

The New York Public Service Commission also comments on the limits of traditional utility revenue models and the need for reform in its Order Adopting A Ratemaking and Utility Revenue Model Policy Framework in Case 14-M-0101. (May 19, 2016). The Commission discusses that dynamic efficiency (i.e. forward-looking investment efficiency) is least well-served by the current framework for ratemaking. In the Order, the PSC takes several steps to design a regulatory model that they believe will better advance New York's clean energy and consumer objectives. The PSC's proposed model provides new revenue and earnings opportunities for utilities based on performance or desired outcomes, instead of capital investment.

Q. Do these recommendations align with the Power Sector Transformation recommendations?

A. Yes. All of them conclude that multi-year rate plans with targeted performance incentive mechanisms shifting the financial incentive toward performance goals are the reasonable next step to transform utility business models. The PST report specifically recommended addressing these two goals through a two-part proposal – a multi-year rate plan that sets a revenue cap and creates an incentive for the utility to manage costs and share savings between the shareholders and customers; and a set of performance incentive mechanisms that offer financial incentives based on performance against defined metrics.

Q. What specific components of a multi-year rate plan did the Power Sector Transformation recommend?

A. The PST report recommended that the Company file a Business Plan that represents a system-wide integrated distribution plan identifying the least-cost portfolio of distribution system investments and covering all initiatives and costs for the next 3-5 years. After approval of capital costs and non-capital costs in the rate case, the utility would absorb the difference if it spent more than budgeted or keep the difference if it is able to spend

less (except for the annual ISR process providing an exception for issues crucial to system reliability that were not reasonably foreseeable at the time of the MRP).

Q. Did National Grid follow that recommendation in making its rate case filing?

A. No. The rate case is for a single test year, although portions of the investments proposed in the PST proposal span multiple years, along with the proposed performance incentive mechanisms.

Q. How can National Grid have a single year rate plan with multi-year incentives?

A. National Grid is requesting that the PUC approve the categories of investments it outlines in its proposed PST and funds allocated to planning advanced metering infrastructure in 2019. It contemplates making further annual filings for both rates and investments. But without both a multi-year structure and connections between rates, revenue requirements, returns, investments, and performance incentives, the utility's business model will not change enough to control the long-term costs of the electric system. This is further exacerbated by the PUC's own bifurcation of the dockets into rate case and PST case, as it severs the connections between utility returns and performance incentives. This shortcoming, however, can be remedied by the PUC going forward.

Q. How can the PUC establish the appropriate connections?

A. The PUC can reintegrate the portions of Docket 4780 that propose to change the utility's business model and compensation, such as performance incentive mechanisms. By considering those proposals in the rate case that sets the rest of National Grid's compensation, the PUC can appropriately balance the levels of compensation between the multiple sources. In doing so, the PUC can set National Grid on the path to utility business model reform, to be furthered by multi-year rate plans in the future.

Q. What changes in compensation do you recommend the PUC makes?

A. The portion of revenue requirements recovered through performance incentive mechanisms should increase while the portion of revenue that is linked to the rate base decreases. Ideally, to maintain a reasonable opportunity for National Grid to earn a fair rate of return on prudent capital investments, this transition should be gradual, and the increase and decrease should be equivalent.

Q. Does National Grid's proposed return on equity conform with this transition to a modern business model?

A. No. National Grid has proposed a return on equity of 10.1%. Horan Testimony at 23. In support of this figure, the company claims that it represents a reasonable, but conservative return in the context of evolving capital market conditions. (*Id.*) However, National Grid overlooks the intended link between such traditional returns and the transformation to a new utility business model and does not propose to reduce its return on equity in proportion to its proposed performance incentive mechanism earnings. Maintaining such a high return on equity further perpetuates the utility's capital bias and keeps the consumer and environmentally focused proposals made in other areas of this case from being truly transformative.

Q. Why do you conclude that 10.1% is a high rate of return on equity?

National Grid's proposed return is higher than recently approved levels in other jurisdictions across the region. For example, the last return on equity approved for Eversource in Connecticut was 9.17%. Connecticut Public Utilities Regulatory Authority, Docket 14-05-06, Decision, December 17, 2014, at 145. A recent proposed decision for Eversource in Connecticut plans to approve a settlement that includes 9.25% return on equity. Connecticut Public Utilities Regulatory Authority, Docket 17-10-46, Proposed Final Decision, April 5, 2019, at 18. National Grid's proposal is also significantly higher than the 9% return on equity that was recently approved for National Grid's subsidiary in New York. Case 17-E-0238, et al., Order Adopting Terms of Joint Proposal and Establishing Electric and Gas Rate Plans, March 15, 2018, at 16.

Q. Are there other jurisdictions where the return on equity is high?

A. Yes, in a recent decision, the Massachusetts Department of Public Utilities approved a 10% return on equity in Eversource's electricity rate case. Massachusetts Department of Public Utilities 17-05, Order Establishing Eversource's Revenue Requirement, November 30, 2017. However, this decision came over the objection of numerous parties, and this level of return on equity is the subject of a current appeal by Massachusetts Attorney General Maura Healey. Massachusetts Supreme Judicial Court Docket SJ-2017-0509.

Q. How can the PUC address this issue?

A. Since a high return on equity like 10.1% increases the utility's incentive to build traditional infrastructure, it is in direct conflict with the intent of Docket 4600 and the Power Sector Transformation process. As I noted above, this and other utility revenues linked to the rate base should be reduced in proportion to performance incentives, currently proposed in Docket 4780. The PUC should integrate the portions of Docket 4780 that propose to change National Grid's business model and consider them in conjunction with the rest of National Grid's compensation.

V. ACADIA CENTER VISION FOR RATE DESIGN AND DISTRIBUTED ENERGY RESOURCE COMPENSATION

Q. Please describe what you mean by the term "rate design."

A. The term "rate design" is a longstanding term that refers to the billing determinants for retail electricity customers and the prices set for each billing determinant. Rate design is an integral part of broader reforms to utility regulation that are necessary, and a regulatory tool that must evolve over time to both accommodate and accelerate a future with widespread local clean energy and a smart and dynamic electric system.

Q. What are the Bonbright principles for rate design?

A. In 1961, James Bonbright laid out a long list of general principles for rate design. These are often summarized, but in full they are:

1. The related, "practical" attributes of simplicity, understandability, public acceptability, and feasibility of application.
2. Freedom from controversies as to proper interpretation.
3. Effectiveness in yielding total revenue requirements under the fair-return standard.
4. Revenue stability from year to year.
5. Stability of the rates themselves, with a minimum of unexpected changes seriously adverse to existing customers. (Compare "The best tax is an old tax.")
6. Fairness of the specific rates in the apportionment of total costs of service among the different customers.

7. Avoidance of "undue discrimination" in rate relationships.
8. Efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use:
    a. In the control of the total amounts of service supplied by the company:
    b. In the control of the relative uses of alternative types of service (on-peak versus off-peak electricity, Pullman travel versus coach travel, single-party telephone service versus service from a multi-party line, etc.).

(Principles of Public Utility Rates, James C. Bonbright, Columbia University Press 1961, p. 291).

Q. Are the Bonbright principles still applicable?

A. These long-standing principles are broadly accepted and are helpful guideposts on many questions. However, they are general and do not necessarily provide concrete answers to regulators dealing with 21st century issues.

Q. What more specific principles for retail rate and DER compensation reform has Acadia Center laid out previously?

A. Based on UtilityVision, Acadia Center has articulated the following four principles:

1. Monthly customer charges should be no higher than the cost of keeping a customer connected to the grid and the related customer service, but can be kept lower based on public policy considerations.
2. Other components of electricity rates can be reformed to better align customer incentives with cost drivers and the value they can provide to the system.
3. Ratepayers must be able to understand significant reforms and have a basis on which to respond and manage bills.
4. Self-generation consumed on-site should be treated the same as reductions in energy usage.

Q. Has the Regulatory Assistance Project proposed a related set of principles?

A. Yes, in a 2015 report titled "Smart Rate Design for a Smart Future", portions of which are attached as Exhibit AC-ML-6, Regulatory Assistance Project (RAP) laid out the following three principles, that are similar to the 4 identified above:

1. A customer should be able to connect to the grid for no more than the cost of connecting to the grid.
2. Customers should pay for grid services and power supply in proportion to how much they use these services and how much power they consume.
3. Customers who supply power to the grid should be fairly compensated for the full value of the power they supply. (p. 6).

Q. What does Rhode Island law require the PUC to consider in evaluating rate design?

A. Pursuant to R.I. Gen. Laws § 39-26.6-24(b), the factors to be considered in rate design are: (1) The benefits of distributed-energy resources; (2) The distribution services being provided to net-metered customers when the distributed generation is not producing electricity; (3) Simplicity, understandability, and transparency of rates to all customers, including non-net metered and net-metered customers; (4) Equitable ratemaking principles regarding the allocation of the costs of the distribution system; (5) Cost causation principles; (6) The General Assembly's legislative purposes in creating the distributed-generation growth program; and (7) Any other factors the PUC deems relevant and appropriate in establishing a fair rate structure.

Q. How has the PUC interpreted this section?

A. To guide its review of National Grid electric rates, the PUC adopted goals, updated rate design principles, and a new Rhode Island Benefit-Cost Framework through Docket 4600.

Q. What are the updated rate design principles that the PUC adopted in that docket?

A. As stated in Guidance Document 4600-A, a proposed rate design may be found reasonable if it does the following:

- 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 PUC recognizes that no one rate design proposal may advance each principle listed above, but each should be addressed so that the PUC can appropriately balance the interests of all parties in setting just and reasonable rates across rate classes and programs.

Q. Do you believe the PUC's principles from 4600-A are consistent with Bonbright's principles and Acadia Center's more specific principles?

A. Yes, I believe they are consistent.

Q. Please describe Acadia Center's long-term vision for rate design and DER compensation from UtilityVision.

A. In the long term, customers should be charged for the products and services they receive and credited for the products and services they provide on a granular basis. Charges should reflect equitable recovery of costs for use of the distribution grid. Credits for exports and other services should reflect the net value, including both benefits and costs to the system. This vision includes time-varying charges and credits for energy supply, transmission, and distribution. There could be charges and credits for new retail-level

markets and products and additional values related to the environment and public health could be reflected as well. All charges and credits, except those that reflect any environmental or public health values, should be on a technology-neutral basis. It may also include well-designed demand charges that are focused around local or system peaks. For customers with distributed generation or storage, netting of energy imports and exports would occur on a granular basis, instead of the current practice of monthly netting for many types of customers.

Q. Are there other public policy goals that must be met in this long-run vision?

A. Yes. In addition to the rate design principles discussed above, this long-term vision also includes customer control over energy costs and equitable access to clean energy options, such as community solar.

Q. Would this long-term vision apply to all customers?

A. Not necessarily. Keeping certain consumer segments, such as low income, on simpler rate structures may be justified by both economics and consumer protection principles.

Q. Please describe any hurdles to this long-term vision.

A. There are many reasons why this long-term vision cannot be set up overnight. It will require advanced metering functionalities, billing system upgrades, energy management technologies that are affordable for small customers, significant customer education efforts, and processes to fairly determine the charges and credits for distinct types of products and services. Statutory changes, notably to net metering structures, may also be necessary to implement certain reforms.

Q. Has Rhode Island taken any significant steps towards this long-term vision?

A. Yes. In Docket 4600 and the PST Report, Rhode Island stakeholders and government agencies laid out pathways to achieve major reforms to the electricity sector. In Docket 4600, the PUC ultimately endorsed several categories of recommendations, including rate design principles, a benefit-cost framework, and goals of the future electric system. In the PST Report, the interagency team, primarily the Office of Energy Resources and the Division of Public Utilities and Carriers, made a wide range of innovative recommendations that Acadia Center enthusiastically endorses.

Q. Given this long-term vision, how does Acadia Center approach the short- and medium-terms?

A. We believe that reforms in the short- and medium-terms must take steps towards this long-term vision and satisfy the relevant rate design principles and public policy goals. Gradualism and customer understanding are also key to implementing reforms. Rate reforms can be phased in, and customer protections like "shadow billing," where customers can see what their bill would be under different rate structures, and "hold-harmless periods," where customers can only benefit from new rate structures, are helpful transition tools. Metering costs and billing system upgrades must also be considered in the short- and medium-terms.

Q. Has Acadia Center proposed a set of short-term reforms?

A. Yes. The Acadia Center document "Sustainable Rate Design: Near-Term Consumer-Friendly Reforms for a Clean Energy Future," attached as Exhibit AC-ML-7, lays out five near-term steps that states across the region can take to begin to make rate design and DER compensation fairer and more accurate, while maintaining or improving incentives for energy efficiency and access to clean energy:

1. Limit reliance on fixed customer charges;
2. Implement Acadia Center's "distribution reliability charge"[6] proposal to begin to account for any proven cross-subsidies due to distributed generation installed by small customers;
3. Offer opt-in time-of-use rates for energy supply;
4. Enable or maintain virtual net metering for community distributed generation, with a robust low-income component; and
5. Begin to align net metering credits with ratepayer value and remove caps on net metering.

Q. What key issues are addressed by these proposed short-term reforms?

A. These short-term reforms reflect gradualism, minimal additional metering costs and billing system upgrades, and several incremental steps to better reflect the costs and

[6] More information about Acadia Center's Distribution Reliability Charge proposal is available at: https://acadiacenter.org/document/distribution-reliability-charge-transitioning-to-sustainable-rate-design/

benefits of customer consumption patterns and exports from distributed generation. One step of particular relevance in a distribution rate case is the beginning of a process to unbundle distribution system costs, or otherwise distinguish between (1) the full embedded costs of the distribution system that must be recovered by the utility, and (2) the value of exported energy to the distribution system. Such a process is key to establishing the proper level of the distribution reliability charge.

Q. How does this apply in Rhode Island and other states in the region?

A. Each state in the region is in a different place on these issues. For example, Rhode Island currently has lower residential customer charges than Connecticut. Rhode Island is having some success offering community DG, but Massachusetts has more. However, unlike Rhode Island, both Connecticut investor-owned utilities offer opt-in time-of-use rates for all residential customers. Similarly, only New York has taken definitive steps to align net metering credit structures with ratepayer value.

Q. Has Acadia Center proposed concepts for medium-term reforms?

A. Acadia Center is beginning to explore concepts for medium-term reforms. This could include:

1. Default time-of-use rates for certain categories of customers, including time-of-use netting for distributed generation customers;
2. Charging for embedded distribution system costs and public policy costs for imports and crediting for value to the distribution system for exports;
3. Incremental avoided environmental and public health compliance costs can be credited for exports on a technology-specific basis; and
4. Charges and credits corresponding to other portions of the electric system (energy, capacity, and transmission) can be symmetric for imports and exports.

Such steps would logically link short-term steps with Acadia Center's long-term vision. Default time-of-use rates and time-of-use netting is a significant step beyond current practices, particularly for DG customers for whom monthly netting is currently the norm. These medium-term reforms would require substantial processes to unbundle distribution values and determine other appropriate credits and charges by time-of-use period and by technology as appropriate.

Q. Must reforms to rate design and DER compensation follow a specific sequence?

A. Each individual reform has prerequisites for implementation, but not every state will need to make each stop along the way. In other words, some jurisdictions may be able to skip straight to reforms that I would describe as medium-term, or some may adopt short term reforms for a number of years before adopting long-term reforms. Lastly, states may be able to apply more advanced reforms to certain customers, primarily larger C&I customers, on a shorter timetable.

VI. MONTHLY CUSTOMER CHARGES

Q. What are monthly customer charges?

A. A monthly customer charge, also known as a fixed charge, is a flat fee paid every billing period by a customer, regardless of how many kWh are consumed or other billing determinants.

Q. What are the direct impacts of higher monthly customer charges on other parts of the electric bill?

A. Higher monthly customer charges mean that less revenue needs to be collected through other portions of rates. For rate classes without demand charges, higher fixed charges mean lower per-kWh rates.

Q. What is National Grid proposing with respect to monthly customer charges?

A. National Grid argues that customer-related costs plus a percentage of demand-related costs should be reflected in monthly customer charges. For the residential rate class as an example, National Grid calculates that monthly customer charges should include $9.61 in customer-related costs and $5.78 in demand-related costs "for a total of $15.39 per month as the maximum fixed charge." Gorman Testimony at 30. Based on this maximum calculation, National Grid then proposes to increase residential customer charges from the current $5 per month to $8.50 per month. Gorman Testimony at 29.

Q. What are the negative impacts of higher customer charges and lower per-kWh rates?

A. There are two primary negative impacts. First, lower per-kWh rates decrease the incentives for energy efficiency investment and limit customer control of bills. Second,

there are significant distributional consequences because smaller customers end up paying more and larger customers end up paying less. This is particularly significant in the residential context. The National Consumer Law Center (NCLC) has shown that low-income households consume less electricity than average, so higher customer charges increase bills for low-income households. An NCLC analysis for the New England states (excluding Massachusetts) with such data is attached as Exhibit AC-ML-8.

Q. Why do some argue that fixed charges should be higher?

A. Utilities across the country often argue that past investments are "fixed" and should therefore be recovered through fixed charges. However, this confuses two concepts. Historical investments are sunk costs, but that does not mean that they should be recovered through fixed charges. Rates should be forward-looking and consider the impact of customer choices on future investments. Nationally, the arguments in favor of fixed charges also align with utility interests in increasing revenue stability and reducing incentives for energy efficiency and distributed generation. In restructured jurisdictions, even decoupled distribution utilities still have an interest in increased revenue stability in terms of timing and the certainty of collections. Also, because companies that invest in transmission lines and other energy resources receive a return on those investments, they have an incentive to discourage local energy production that could reduce the need for additional infrastructure investment.

Q. What downsides do high fixed charges present to utilities?

A. In the long run, high fixed charges encourage customers to disconnect from the grid entirely. As the costs of distributed generation and storage continue to fall, this may become a viable option for increasing numbers of ratepayers.

Q. How do fixed charges relate to broader principles of economic regulation?

A. One key role of public utility regulation is to approximate the incentives of market competition and prevent monopolistic behavior. Utility claims about the necessity of recovering costs through fixed charges are definitively disproven by the numerous competitive industries where large fixed investments are recovered through per-unit purchases by consumers. This includes oil refineries where consumers pay for gasoline by the gallon, and farms where consumers pay for apples by the pound.

Q. How do these considerations relate to the previously described rate design principles?

A. The negative impacts of higher customer charges inform Acadia Center's first principle of rate design reform that monthly customer charges should be no higher than the cost of keeping a customer connected to the grid and the related customer service but may be kept lower based on public policy considerations. Relatedly, high customer charges violate the more general rate design principles of efficiency and fair cost allocation among customers, as well as public policy principles around equity for low-income customers.

Q. What are the issues with National Grid's calculation and proposal for monthly customer charges?

A. First, it is inappropriate to include any demand-related costs in the customer charge. Second, National Grid applies over-inclusive definitions, which increases their estimate of customer-related costs. Lastly, these calculations, including the full allocated cost of service study, must be updated to reflect lower federal tax rates due to the passage of H.R.-1, The Tax Cuts & Jobs Act.[7]

Q. Why is it inappropriate to include demand-related costs in the customer charge?

A. As discussed above, the proper definition for the maximum reasonable customer charge is based on the cost of connection for an individual customer, which is limited to the costs of a simple meter, billing expenses, the service drop, and certain elements of customer service. All other costs can be shared among customers based on billing determinants related to system usage. This practice is equitable, efficient, and consistent with good regulatory principles. This does not mean that current rate design practices are perfect, but National Grid does not identify a compelling reason to adopt a significantly more expansive definition of customer charges.

Q. What are the issues with National Grid's definition of customer-related costs?

A. National Grid uses a definition of customer-related costs that is more expansive than the cost of connection for an individual customer. National Grid identifies $50,774,000 in

[7] The Company has reportedly updated its allocated cost of service study to reflect the changes in federal tax code as of April 5th, however Acadia Center has not yet been able to review these documents.

customer-related costs for the residential rate class, divided up between the secondary distribution category and the billing category. Schedule HSG-1C-1. In the billing category, there are numerous accounts included that are not necessarily a part of the cost of connection, namely general plant (account 390), miscellaneous expenses for distribution operation (account 588), and several categories under the heading of customer assistance that may be more closely related to sales and advertising (accounts 909, 910, 912, and 916). Schedule HSG-1F-5. However, the inclusion of numerous administrative and general operating expenses raises the largest question, since they account for $12,322,000 of the total customer-related costs. Schedule HSG-1F-5, page 4, row 118. Removal of these administrative and general costs would remove 24.27% of the overall customer-related costs,[8] and would lower the estimated customer-related costs per billing month to $7.28.[9]

Q. What is the impact of lower federal tax rates due to the passage of H.R.-1, The Tax Cuts & Jobs Act?

A. Federal taxes are reflected in the revenue requirement for utilities, and thus are reflected in the relevant portions of the allocated cost of service study. Lower federal tax rates would thus be expected to result in lower unit costs in the allocated cost of service study. However, National Grid did not prepare an allocated cost of service study that reflects changes from the recent federal tax law prior to my drafting this testimony. Response to Acadia Center 1-2.[10] This means that all estimates of customer-related costs in the current allocated cost of service study used by National Grid and in my testimony are overestimates.

Q. What do you conclude regarding National Grid's proposed residential customer charge based on your analysis and the above factors?

A. The proposed $8.50 monthly customer charge for the residential rate class is almost certainly higher than a correctly calculated estimate of customer-related costs, particularly when updated to account for the recent federal tax law.

[8] $12,322,000 / $50,774,000 = 24.27%
[9] $9.61 * (1 - 24.27%) = $7.28
[10] The Company has reportedly updated its allocated cost of service study to reflect the changes in federal tax code as of April 5th, however Acadia Center has not yet been able to review these documents.

Q. What do you recommend for customer charges more generally?

A. The PUC should order National Grid to exclude inappropriate categories of costs from customer-related costs in its new allocated cost of service study that is also updated for the recent federal tax law. In the absence of correctly calculated and updated information, it would be reasonable to leave the residential customer charge at the current level of $5. A similar analysis would also apply to the commercial and industrial rate classes, and the proposed customer charges should also be examined for these rate classes.

Q. How does your recommendation on monthly customer charges relate to the rate design principles from Guidance Document 4600-A?

A. Capping customer charges at the cost of connection meets most of those rate design principles and is consistent with the others. This reasonable definition of monthly customer charges, with the remainder of costs recovered through variable billing determinants, leads to more affordable and environmentally responsible electricity service today and in the future, promotes economic efficiency and efficient price signals, empowers consumers to manage their costs, is transparent and understandable, assists low-income customers, is consistent with policy goals, and encourages appropriate investments. This definition of customer charges allows for safe and reliable electricity service, fair opportunity for utility cost recovery, and innovations with future rates that provide fair compensation for services and addressing externalities. Since this proposal is consistent with the status quo, it also satisfies the principle of gradualism.

VI. OPT-IN TIME OF USE RATES

Q. What are time-varying rates, and how can they reduce the costs of the energy system?

A. Time-varying rates are rates that vary based on the time the energy is taken from the grid. Many cost drivers in the electric system are determined by the timing of electricity consumption. For example, system-wide energy supply costs are driven by wholesale energy and capacity markets. Because of the structures of these markets, time-varying rates can provide better economic incentives to reduce overall costs and provide customers with opportunities to save money by taking advantage of low cost hours.

Q. Are there considerations to ensure that consumers understand and benefit from time-varying rates?

A. Significant rate innovations should be implemented on a phased and strategic schedule to ensure customers benefit from time-varying rates and other rate changes. Consumers must be able to understand significant reforms and have a basis on which to respond and manage bills. Clear information and education should be provided to allow consumers to understand their electricity bill and what actions they can take to reduce it.

Q. What are time-of-use rates?

A. Time-of-use rates are a narrower category of time-varying rates with predefined time periods and prices, such as a higher price from noon to 8 pm on non-holiday weekdays and a lower price at all other times. Time-of-use rates can have more than two periods per billing cycle, but generally they are fixed and defined in advance, unlike critical peak pricing or dynamic pricing.

Q. What are opt-in time-of-use rates?

A. Opt-in time-of-use rates are elective for consumers, where the default is typically the current flat rate structure.

Q. What does Acadia Center recommend with respect to opt-in time-of-use rates?

A. Opt-in time-of-use rates should be made available for residential and small business rate classes as soon as possible, with significant outreach, education, and customer tools to achieve a reasonable adoption rate.

Q. How is this different than National Grid's recommendation for time-varying rates in its Power Sector Transformation testimony?

A. National Grid recommends rollout of opt-out time-varying rates in 2023, after a year of customer education efforts. National Grid PST Testimony, page 36. This means that no time-varying rates would be available for most Rhode Island citizens for the next five years. I believe this approach would miss significant opportunities in the meantime (1) to get meaningful customer response through load shifting, energy efficiency investments targeted at peaks, and customer-sited storage, (2) to earn more hands-on experience for Rhode Island customers, (3) to create a market for energy management technologies, and (4) to learn lessons for the rollout of opt-out time-varying rates.

Q. Do opt-in time-of-use rates require advanced metering?

A. No, they do not. In many states, including National Grid's service territory in New York, opt-in time-of-use rates can be offered using an upgrade to existing AMR meters. This upgrade does have some incremental capital costs, and this offering may require modest changes to existing billing systems.

Q. What did Docket 4600 and the Power Sector Transformation recommend for opt-in time-of-use rates?

A. Although no firm recommendation was made on this point, the stakeholder report for Docket 4600 noted that "An opt-in approach should be considered for any transition period to any opt-out requirement." Docket 4600 Stakeholder Report at 13. Acadia Center believes that this approach for the transition period is beneficial for customers and the electric system and ultimately necessary to facilitate successful opt-out time-varying rates.

Q. How does your recommendation on opt-in time-of-use rates relate to the rate design principles from Guidance Document 4600-A?

A. Offering opt-in time-of-use rates meets most of those rate design principles and is consistent with the others. Correctly designed opt-in time-of-use rates promote economic efficiency and efficient price signals, empowers consumers to manage their costs, are transparent and understandable, is consistent with policy goals, encourage appropriate investments, and provide a pathway to innovations with future rates that provide fair compensation for services and addressing externalities. This recommendation allows for safe and reliable electricity service, and a fair opportunity for utility cost recovery. This recommendation is designed to smooth the transition to opt-out time-varying rates in the longer term and is necessary to meet the principle of gradualism from that perspective.

VII. CONCLUSION

Q. Do you believe that the current division of issues between Docket 4770 and Docket 4780 should be maintained?

A. No. This procedural bifurcation should not dictate the outcome of substantive issues or override Rhode Island's larger policy goals. As the performance incentive mechanisms and recovery for grid modernization improvements filed in the proposed PST should impact the returns that National Grid earns otherwise, it is important to consider such issues in this docket. Performance-based compensation that is being added through National Grid's proposed PST should be determined in this docket and proportionally reduce return on equity and other traditional utility compensation.

Q. Do you believe that the PUC should approve National Grid's proposed return on equity?

A. No. National Grid's proposed return on equity is likely too high, well above returns that National Grid has recently agreed were reasonable. More significantly, high returns on equity perpetuate incentives for utilities to make as many capital investments as possible, contrary to the intent of Docket 4600 and the Power Sector Transformation process. The PUC should scrutinize the allowed returns and incorporate in its decision consideration of increases in company earnings from any approved performance incentive mechanisms.

Q. Do you believe the PUC should approve National Grid's proposed residential monthly customer charges?

A. No. Customer charges should be capped at properly calculated customer-related unit costs and may be lower based on public policy principles. The PUC should scrutinize National Grid's corrected and updated cost of service study, but based on currently available evidence, an increase in residential customer charges does not appear to be warranted.

Q. Do you believe the PUC should order National Grid to implement opt-in time of use rates immediately?

A. Yes. The PUC should order National Grid to make opt-in time of use rates available for residential and small business rate classes as soon as possible, and provide significant outreach, education, and customer tools to achieve a reasonable adoption rate.

Q. Does this conclude your testimony?

A. Yes, it does.

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PROFESSIONAL EXPERIENCE

ACADIA CENTER, Boston, MA
Staff Attorney, September 2013-Present

- Leader of Acadia Center's regional work on electricity rate design, distributed energy resource compensation, and electric vehicles
- Member of the MA Zero Emission Vehicle Commission, appointed by Governor Baker

CONNECTICUT FUND FOR THE ENVIRONMENT, New Haven, CT
Energy Fellow, September 2012-August 2013
Undertook administrative and legislative advocacy for clean energy. Worked with numerous stakeholders to form an organization to advance commercial sector energy efficiency in Stamford, Connecticut.

NERA ECONOMIC CONSULTING, ENVIRONMENT GROUP, Boston, MA
Associate Analyst, July 2007-July 2009
Analyzed market impacts of federal energy and climate change legislation with national and regional economic modeling. Performed economic analysis for state regulatory filings and comments on proposed federal regulations. Developed reports to convey results to corporate officers, lawyers, policy experts, government officials, and the general public. Assisted with the development of expert testimony for regulatory filings.

EDUCATION

NEW YORK UNIVERSITY SCHOOL OF LAW, New York, NY
J.D., *cum laude*, May 2012

- Research Assistant and Teaching Assistant for Dean Richard Revesz
- Environmental Law Clinic at Natural Resources Defense Council

HARVARD COLLEGE, Cambridge, MA
A.B. in Applied Mathematics (with a focus in Economics), *cum laude*, June 2007

SELECTED PUBLICATIONS

- Co-Author of Acadia Center's UtilityVision: Reforming the Energy System to Work for Consumers and the Environment. UtilityVision outlines specific steps needed to modernize the grid and create a clean, consumer-friendly and environmentally-friendly energy system.
- Co-Author of Charge Without a Cause: Assessing Electric Utility Demand Charges on Small Consumers, with Paul Chernick (Resource Insight), John Colgan (former Commissioner at the Illinois Commerce Commission), Rick Gilliam (Vote Solar), and Douglas Jester (5 Lakes Energy).
- Co-Author of Charging Up: The Role of States, Utilities, and the Auto Industry in Dramatically Accelerating Electric Vehicle Adoption in Northeast and Mid-Atlantic States, with Jennifer Rushlow (Conservation Law Foundation), Gina Coplon-Newfield (Sierra Club) and Emily Norton (Sierra Club).
- Author of *Lack of Judicial CAIR:* Chevron *Deference and Market-Based Environmental Regulations*, 20 N.Y.U. ENVTL. L.J. 227 (2013).

Accounting for Big Energy Efficiency in RTO Plans and Forecasts: Keeping the Lights on While Avoiding Major Supply Investments

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ABSTRACT

States in several regions are investing in "Big EE"—defined as energy efficiency programs with annual energy savings of around 2% or more of retail sales—to meet significant portions of customer energy needs. Energy efficiency is the largest future energy resource in several states, and its share of the total resource mix is growing quickly. Regional Transmission Organizations (RTOs) in these regions are examining their planning practices to consider and account for the impacts of Big EE, now that energy efficiency is no longer background noise in their forecasts. It is crucial to neither under-count nor over-count the impacts of Big EE: on the one hand, under-counting will lead to billions of dollars of unneeded supply and transmission investments, thereby eliminating a portion of the economic value of the EE programs; on the other hand, over-counting the impacts will result in reductions in system reliability. Since the stakes are high, several RTOs are paying closer attention, although questions remain about the accuracy and effectiveness of the revised RTO planning methods. In this paper we review the changing planning and forecasting practices of RTOs in two regions that have substantial EE programs by analyzing how RTOs: (1) treat EE in their forecasts, (2) forecast EE impacts in future years beyond the time period covered by available EE plans, (3) distinguish energy vs. peak demand impacts, and (4) address the performance uncertainties and risks of future EE, including any discounting practices. We conclude with a summary of best practices to date among RTOs.

Introduction

In this paper we examine the forecasting methods and practices of two RTOs—ISO New England (ISO-NE) and PJM (the RTO covering the Pennsylvania, New Jersey, and Maryland area) —to assess the importance of accounting for EE impacts in the forecasts used for transmission planning. We chose these two RTOs because of our awareness of the significant EE programs in the two regions, plus some differences in how the two RTOs were addressing EE in their planning and forecasting efforts.

First, we review the EE forecasting practices, methods, and results at ISO-NE. Second, we summarize the practices at PJM and analyze the likely effects of including and accounting for EE impacts in the PJM forecasts. By comparing and contrasting the different forecasting practices and the forecast results at the two RTOs, we document the current state-of-the-practice (as of 2013) at these two RTOs and identify potential improvements for the future.

Accounting for EE in ISO-New England Transmission Planning

The six New England states have long been leaders in state-funded energy efficiency, often occupying the top slots in the annual ACEEE State Energy Efficiency Scorecard. Some states in the region have been achieving EE levels near 2% of retail sales for several years, and all states are achieving savings that exceed 1% of annual retail sales. In addition, ISO New England allows providers of EE to offer their portfolio as a resource into the region's wholesale forward capacity market, competing alongside traditional and renewable generation to meet the ISO-NE's capacity requirement to operate a system that will reliably serve forecast demand.

Every year, the ISO-NE develops and publishes its Regional System Plan (RSP), which details the energy and peak load forecasts for the upcoming ten years, lists approved transmission projects, and contains discussions of a number of key issues in the region, such as state Renewable Portfolio Standards, possible factors affecting existing generation stations, and key fuel issues such as the natural gas pipeline infrastructure. Since the preparation of RSP12 in 2012, the ISO has also included a forecast of future EE installations and, importantly, incorporates this forecast into the energy and peak load forecasts that it uses for transmission planning.

History

On June 16, 2006, the FERC officially accepted the ISO-NE proposal for a new form of capacity market for the region, the Forward Capacity Market. Two key features of this market are relevant here. The first is that it is a forward market, meaning that an auction is held to procure capacity for a delivery period that is in the future—in this case three years after the auction. The second is that the market rules allows for bidding into the system of not only generation supply, but also demand reductions, including energy efficiency. In February 2008 more than 600 MW of EE cleared in an auction, with an obligation to deliver over a 12-month period starting on June 1, 2010. Ten months later in December 2008, more than 200 MW of additional EE cleared in a second auction, with an obligation to provide savings for a 12-month period beginning June 1, 2011. Ten months after that, another 200 MW of EE cleared for June 1, 2012. A clear trend had begun.

Figure 1 prepared by ISO-NE shows the growth of energy efficiency and demand resources in ISO-NE markets in the region, specifically in the ISO-NE Forward Capacity Market (FCM), since 2010 (Yoshimura 2014). The figure shows historical demand resources (in gray on the left of the chart) prior to the start of, and forecast demand resources since the beginning of, the ISO-NE Forward Capacity Market. Energy Efficiency is labeled by ISO-NE as a "Passive Demand Resource" to contrast it from "active" demand resources that respond to a reliability call or price.

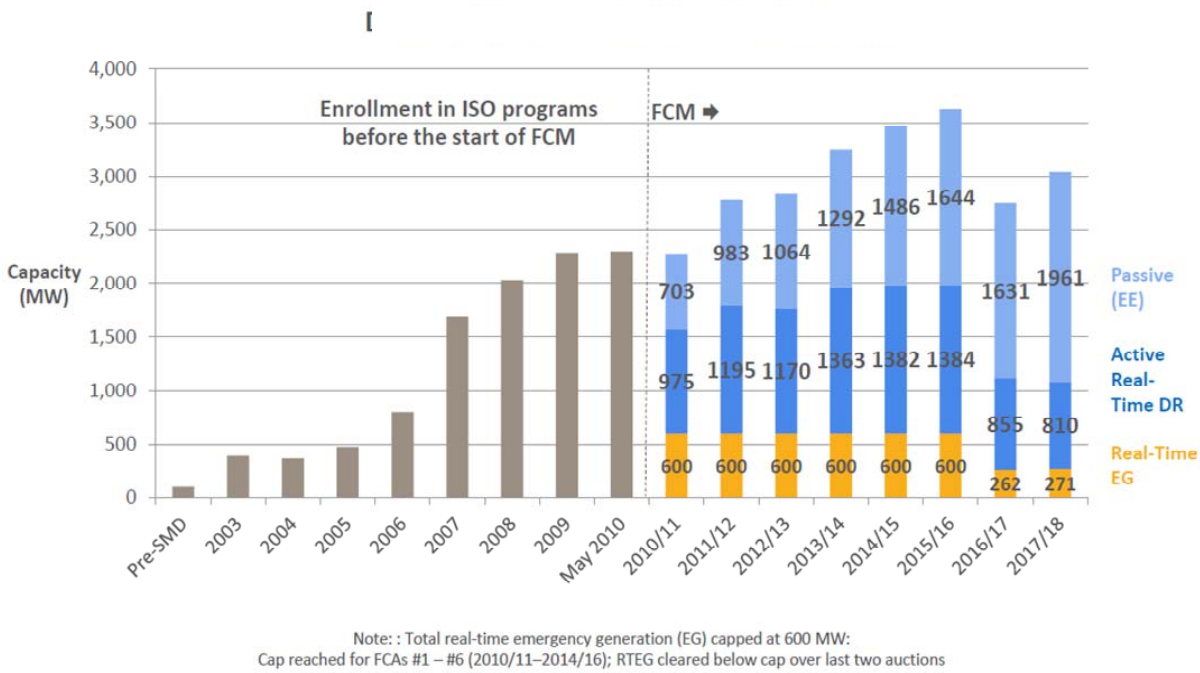

Figure 1. Participation of Demand Resources in the ISO-New England Forward Capacity Market (ISO-NE 2013a).

However the ISO-NE planners were faced with a new problem to solve. They now needed to account for heretofore ignored EE in their load forecasts. With a financial obligation to deliver specific amounts of EE in future years, it became relatively straightforward to do this for a time period of three years into the future. During the spring and summer of 2010, the ISO was developing with their stakeholders the contents of RSP11. At that point, the first three FCM auctions had already occurred, and EE had cleared the MW values listed above. The ISO could easily use these values in their load forecasts, and did so—using the level of EE resources that cleared in the FCM auctions.

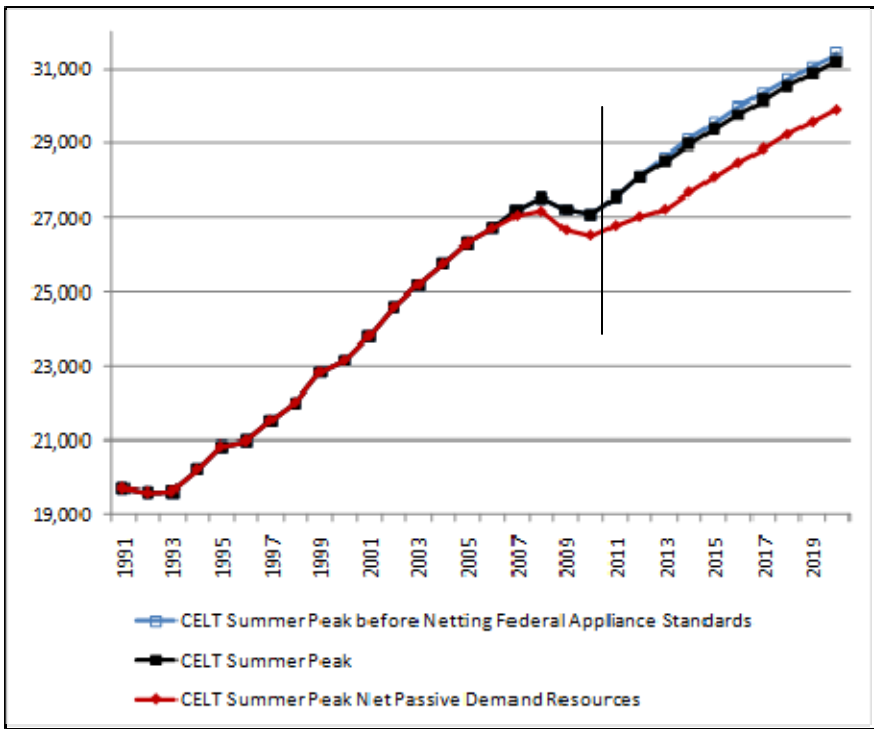

Figure 2. Historical and forecast annual summer-peak loads, 1991 to 2020.[1]
(ISO-NE 2011, Fig 3-3)

The problem, at that time, was that the ISO was assuming that no new EE would be installed after the time period for which the EE resource had assumed an obligation in the capacity market. In Figure 2, from RSP11, new EE was assumed for June 2011, June 2012, and June 2013, but beyond those years ISO-NE assumed 0 MW of new EE would be installed. The lines cease their growing divergence and become parallel in the final six years of the forecast. There was no obligation for new EE to be delivered, so ISO-NE assumed none would be. The program administrators, state agencies, and state regulatory commissioners familiar with EE budgets and planning knew that this assumption was wrong, and argued to change this practice. After some discussion, ISO-NE agreed, and formed an Energy Efficiency Forecast Working Group.

Since its inception in early 2012 the ISO-NE, with the input of the EE Forecast Working Group, has developed a methodology for including a forecast of EE that will be installed in the years beyond those where obligations have already been taken in the FCM. For example, in the most recent final forecast to be included in the upcoming RSP14, the ISO will use FCM obligations for the summers of 2014, 2015, 2016 and 2017 because the auctions for these time periods have already taken place. ISO-NE will then use the EE forecast to project the amount of EE that will be installed for 2018-2023—the remaining six years of the RSP 10-year planning period.

[1] In the figure, CELT stands for the ISO New England annual report on Capacity, Energy, Load and Transmission.

Summary of the EE Forecast Methodology

After several months of discussions, ISO-NE and the EE Forecast Working Group agreed on a methodology that would be used to forecast the amount of EE that the ISO would include in its forecasts of energy and peak loads. Each program administrator submitted to ISO-NE data from their recent annual reports on budgets approved, expenditures, and planned and achieved energy, summer peak and winter peak savings. These data were categorized by program and end use, and the data from the latest annual reports are now collected each year. ISO-NE staff aggregate the data by state and then further compile to a regional level to arrive at historical cost and savings trends. The costs, energy savings and peak load reductions are then used to arrive at historical production cost values (e.g., cost per MWh saved) and peak-to-energy ratios. These historical data on EE performance are then combined with data on future budgets to forecast future EE impacts. Specifically, using the ISO-NE formulae below, the historical production cost and peak-to-energy ratios are applied to the approved and/or forecast future EE budget amounts, with various discounting factors, to arrive at a forecast future amount of EE energy savings and peak demand reductions by state (ISO-NE 2014a).

1) MWh = [(1-BU) * Budget $] / [$/MWh * PCINCR]

where:

Budget $ = an estimate of the dollars to be spent on EE ($)
(System Benefit Charge + RGGI + FCM + Policy)

BU = budget uncertainty (%)

$/MWh = production cost ($/MWh)

PCINCR = production cost increases (%)

2) MW = MWh * PER

where:

PER = peak-to-energy ratio (MW/MWh)

Figure 3. ISO-NE methodology and formulae for forecasting the amount of EE.

The discounting factors used by ISO-NE are important, have been somewhat controversial, and continue to be debated. For example, ISO-NE assumes that in all six states the production cost per unit of savings will rise annually at a rate of 5% plus 2.5% for inflation. The ISO makes no counter-assumption for improvements in the cost of program delivery or other economies of scale. In certain states an additional Budget Uncertainty factor is applied, which further discounts the amount of assumed new EE in future years; this factor has been discussed and applied more in states that have underspent their authorized EE budgets in recent years. While numerous stakeholders have acknowledged that ISO-NE is to be commended for having an EE forecast at all, many parties have also commented that these discounting factors have no specific basis in fact (for example, NESCOE 2014; ISO-NE 2014b). Stakeholders have also suggested that ISO-NE should use the state forecasts of future EE energy savings and peak demand reductions, when available, directly rather than the ISO method of applying historical production costs and peak-to-energy ratios to future EE budgets.

Even with the discounting factors applied by ISO-NE, the results of the EE forecast are very significant. The preliminary forecast for the RSP14 planning period (with EE impacts

incorporated) estimates an annual average increase for the six-state region of 204 MW. From 2017-2023 this amounts to a peak load forecast that is 1,426 MW lower than it would have been absent this EE forecast. That amounts to 1,426 MW of load on a hot summer day that no longer needs to be served by the transmission system. Figure 4 from RSP13 published in October 2013 shows this result clearly, with the RSP13-FCM-EEF line (Regional System Plan 2013 minus FCM, minus EE Forecast, the bottom line in Figure 4) representing the forecast summer peak accounting for the new EE forecast.

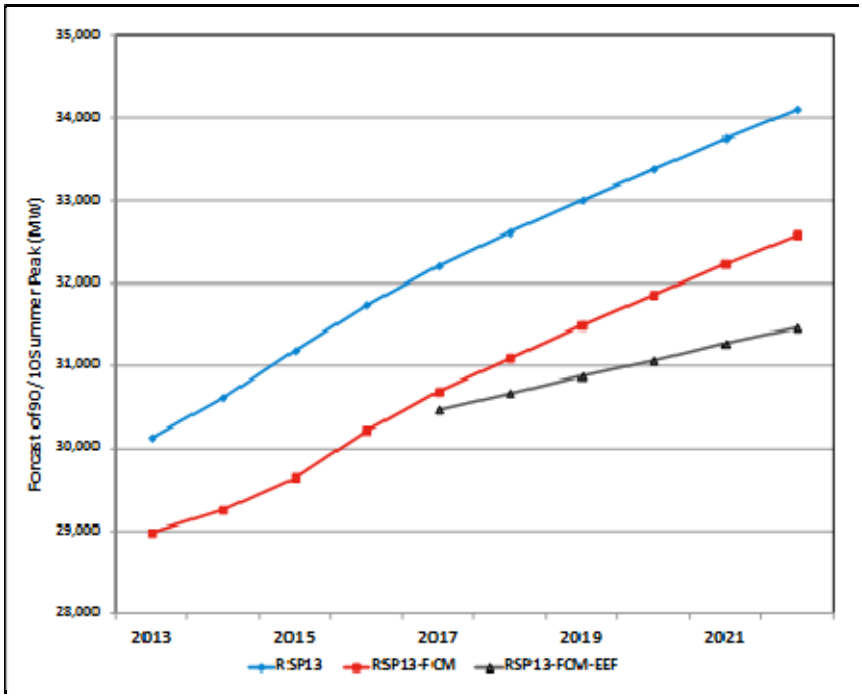

Figure 4. Impact of EE on ISO-New England Forecast of Summer Peak through 2022 (ISO-NE 2013a).

More specifically, Figure 4 shows the revised RSP13 summer peak demand forecast (90/10) (diamond), the load forecast minus FCM #7 auction results through 2016 (square), and the load forecast minus FCM results and minus the energy-efficiency forecast (triangle) for 2017 to 2022 (MW) (ISO-NE 2013a, 41).

Without EE in the FCM, the forecast peak load in 2022 would have exceeded 34,000 MW. With just the four years of FCM results already known, this amount drops to approximately 32,500 MW, a drop of more than 1,500 MW. When the results of the EE forecast are included, the amount drops further to roughly 31,500 MW.

Although the RSP energy forecast is not specifically used for transmission planning, the forecast of annual energy is even more striking. As shown in Figure 5, with the inclusion of an EE forecast, energy use is assumed by the regional system planner to be essentially flat in New England for the upcoming 10-year period.

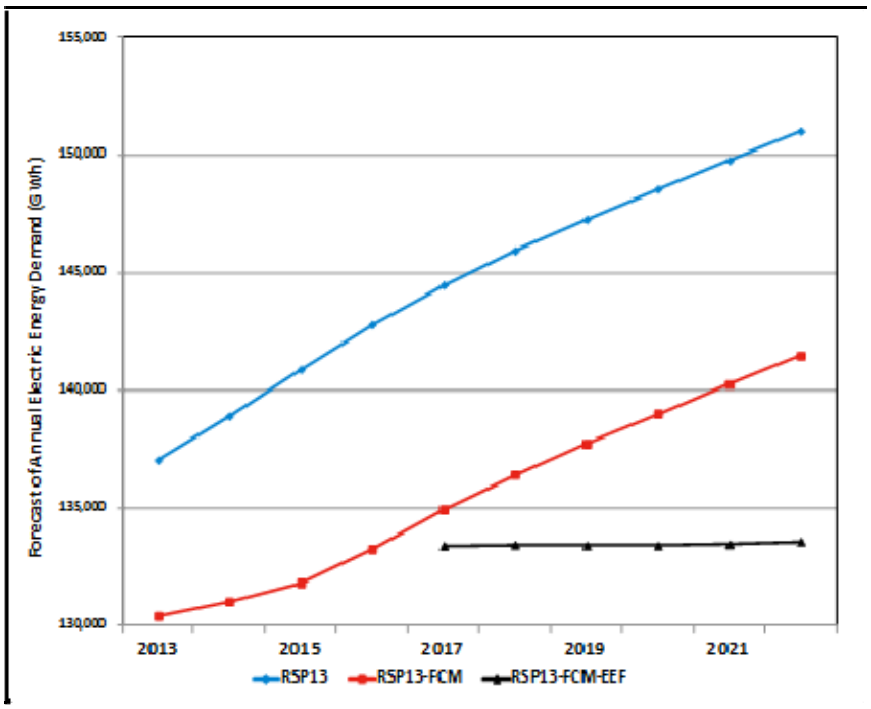

Figure 5. Impact of EE on ISO-New England Forecast of Annual Energy through 2022 (ISO-NE 2013a).

Deferral of Transmission Projects

In the ISO-NE planning process, the inclusion of the EE forecast into the load forecasts is not merely hypothetical or academic. In early 2012, the ISO conducted a follow-up assessment of its New Hampshire-Vermont Transmission System Needs Analysis and Solutions Study (ISO-NE 2012c) in which it included the newly released proof-of-concept Energy Efficiency Forecast (Ehrlich and Winkler 2011). In a March 15, 2012 presentation, the ISO announced that a total of approximately $265 million in previously-identified line upgrades, capacitor additions, and other transmission needs would be avoided or deferred in Vermont and New Hampshire. While ISO staff cited a number of factors that led to the changes, including small additions of demand resources and renewable energy projects, the main reason for the deferrals was a 180 MW load reduction in the NH-VT area documented in the new EE forecast. These initial changes were incorporated into the 2012 Regional System Plan, which stated that "[a] number of transmission system upgrades were identified, which are no longer required within the 10-year planning horizon and could be deferred from the preferred solution identified in the New Hampshire/Vermont Solutions Study. These deferred transmission system upgrades are located in almost every portion of the New Hampshire and Vermont transmission systems" (ISO-NE 2012a, 79-81).

More than a year later, the ISO-NE again came before the Planning Advisory Committee to present the results of an updated New Hampshire-Vermont Needs Assessment (ISO-NE 2013b). In this study, the ISO included the final Energy Efficiency Forecast for 2012, which had been presented to the Planning Advisory Committee on April 18, 2012 (ISO-NE 2012b). The updated analysis showed that, due to an additional approximately 80 MW load reduction in the final EE forecast, the need for a new 345 kV line at an additional cost of $157 million could be

deferred (ISO-NE 2013b, slide 36). These deferred transmission system upgrades were incorporated and memorialized in the 2013 Regional System Plan (ISO-NE 2013a, 76).

Together, incorporating the EE Forecast into ISO-NE transmission planning has resulted in over $420 million of deferred transmission upgrades in New England. As the EE Forecast is applied and reflected in future needs assessments, and as the level of EE investments grow in New England, we expect that additional ratepayer savings will be identified.

Potential in the PJM Territory

There is no obvious reason why the EE forecast methodology used in New England cannot also be used in other RTO regions. The auction held by PJM to purchase capacity for their 2017-2018 power year cleared 1,340 MW of EE, which was 0.78% of the total unforced capacity obligation for that year of more than 171 GW. The total amount of EE being installed in PJM territory is certainly larger than this amount, but this is how much was offered into that market and cleared. While this amount is a smaller percentage than we have seen clear in the ISO-NE capacity market auctions, below we address the possibility of using a similar EE forecast methodology in the PJM territory.

Current PJM Transmission Planning Practices

PJM produces an annual load forecast for the RTO region and for each individual zone. As is done in other regions, these are based largely on economic forecasts and historical weather data. PJM's annual Regional Transmission Expansion Plan (RTEP) considers transmission projects needed for reliability throughout the region. The PJM load forecast provides the peak loads for testing the transmission system in that year's RTEP process (PJM 2013b). The RTEP covers transmission planning for both a short-term (five years) and long-term horizon (fifteen years). For instance, the 2013 PJM Load Forecast is used in the 2013 RTEP, which evaluates transmission capability under a short-term horizon for 2018 and a long-term horizon for 2028 (PJM 2013a).

The RTEP process includes a series of stress tests on the PJM grid to see where transmission bottlenecks occur under a number of sensitivities. The load levels used in these tests are derived from the PJM peak load forecast, after subtracting out demand-side resources, since "the status and availability of demand resources can have a measurable impact on the assessment of future system conditions that drive the need for new transmission to meet load serving responsibilities."[2] Thus the forecasting of demand-side resources has direct implications for transmission planning. This bears repeating: PJM includes a sensitivity forecast that includes demand-side resources, but ignores them in the forecast of peak load used for planning purposes.

Unfortunately, demand-side resources are not projected into the future by PJM as is done for peak load. Demand response (or "load management") has been incorporated into the PJM's capacity auction since its inception, and energy efficiency was incorporated in the 2011/2012 delivery year. For planning purposes, only the amount of energy efficiency and demand response that clears each auction is included in the PJM peak load forecasts. PJM assumes that no energy efficiency will exist in years beyond the most recently cleared capacity auction obligations. This is the same method that was originally used by ISO-NE. This planning practice continues despite

[2] 2013 RTEP: Inputs, Data, Assumptions and Scope, p.17. Available here: http://www.pjm.com/~/media/documents/reports/rtep-plan-documents/2013-rtep-process-white-paper.ashx

readily-available energy efficiency planning data at the state level and continually decreasing PJM load forecasts for each year (see Figure 6 below).

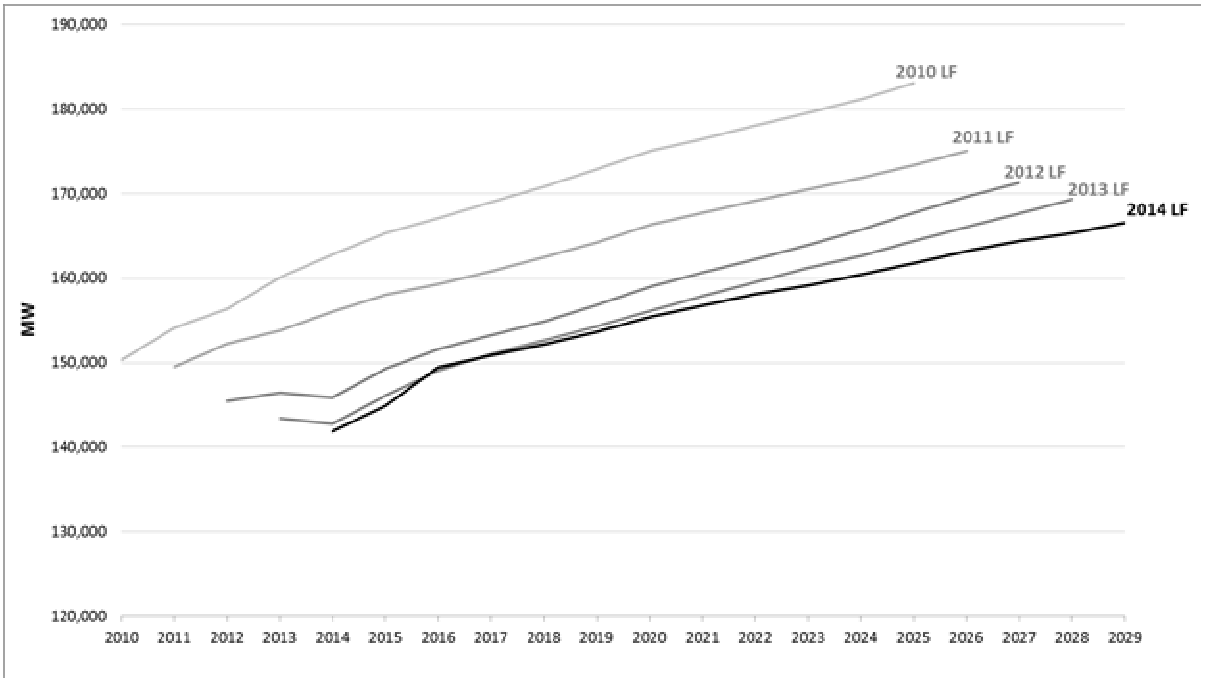

Figure 6. PJM Annual Non-Coincident Peak Load Forecasts, from corresponding RTEP reports.

A Simple Option to Incorporate EE into PJM Planning

A proper forecast of peak load in PJM would take into account the downward trend in previous load forecasts. We have not provided a specific proposal to address that defect here. However, we demonstrate how inclusion of forecasted new energy efficiency (i.e. beyond the capacity auction delivery year) would affect transmission planning.

As described above, RTEP planning currently only counts energy efficiency that has cleared the capacity market. However, the 2010 RTEP evaluated a sensitivity of increased energy efficiency. To demonstrate the impact of new energy efficiency, we assumed the average annual new energy efficiency that was listed in RTEP 2010 – 718 MW (see Table 1 below) – for each year after 2016.

Table 1. 2010 RTEP Available Energy Efficiency (Table 4.1)

Year	Energy Efficiency (MW)	Change from previous year (MW)	Year	Energy Efficiency (MW)	Change from previous year (MW)
2010	471		2018	6,792	*554*
2011	1,216	*745*	2019	7,516	*724*
2012	2,030	*814*	2020	8,489	*973*
2013	3,167	*1,137*	2021	9,042	*553*
2014	4,127	*960*	2022	9,579	*537*
2015	5131	*1,004*	2023	9,986	*407*
2016	5,688	*557*	2024	10,399	*413*
2017	6,238	*550*	2025	11,241	*842*
			Avg.Increment		***718***

Adding new energy efficiency resources into projected net peak load (equal to gross peak load minus demand-side resources) could lead to dramatic reductions in capacity and transmission needs. Figure 7 demonstrates this by incorporating 718 MW of new energy efficiency each year into the 2014 PJM Load Forecast. By 2020, the difference between these two projections (the black solid line compared to the dashed line) is 2,743 MW and by 2029 it is more than 8,900 MW. These represent significant reductions in net peak load, 2% and 5% of the region's forecast net peak load in 2020 and 2029, respectively.

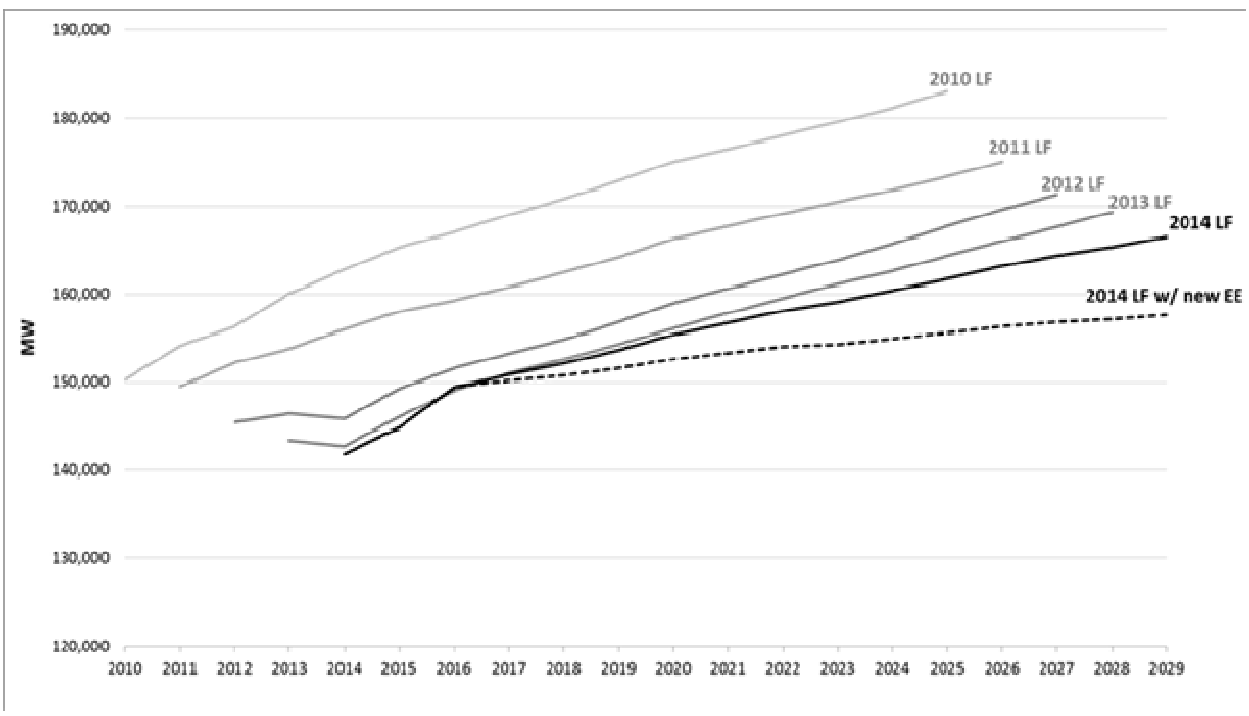

Figure 7. Impact of EE Forecast on the 2014 PJM Non-Coincident Peak Load Forecast.

Figure 8 overlays the deferral of hypothetical transmission projects by indicating their "year of need" using the 2014 PJM Load Forecast compared to an alternative forecast that

includes new energy efficiency resources each year. Including PJM's own estimate of incremental EE delays the need for additional transmission from 2019 to 2021 and from 2022 to 2029—simply due to accounting for new energy efficiency resources after 2016. Any transmission projects whose year of need is currently estimated to be after 2022 would theoretically be deferred indefinitely if this method for including EE was included in the load forecast.

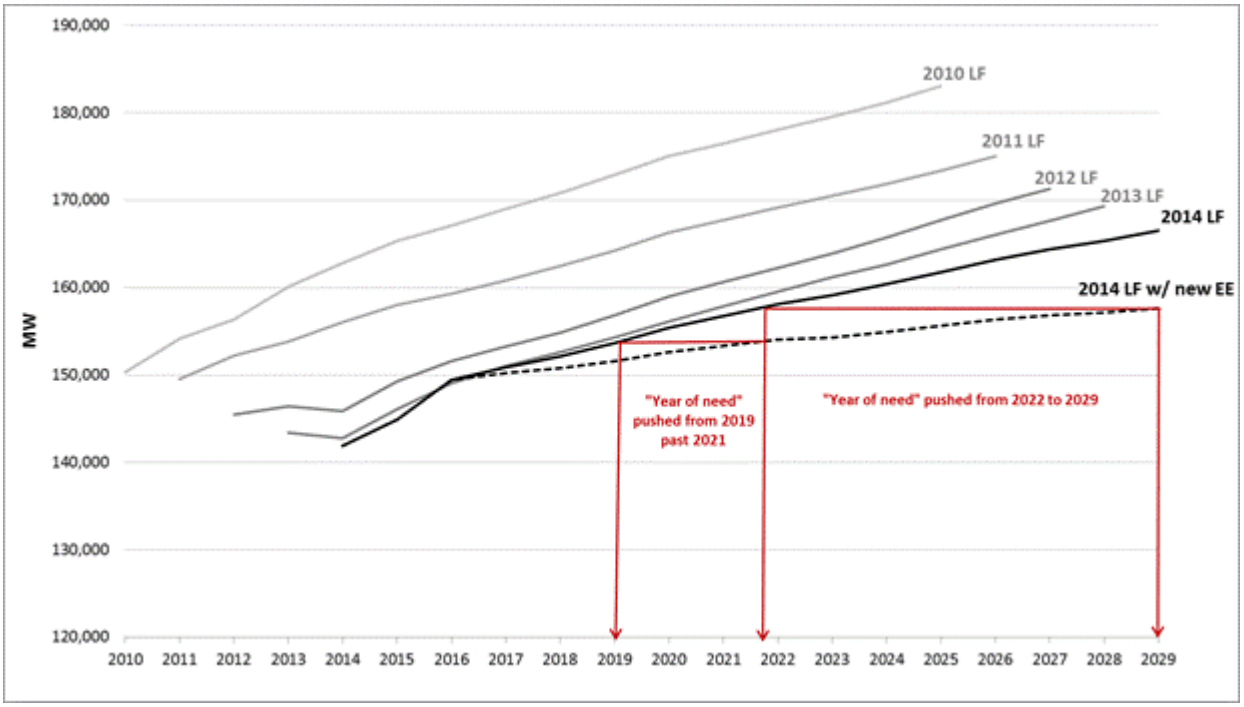

Figure 8. Demonstration of Deferral of Transmission Project Year of Need. *Source:* 2010, 2011, 2012, 2013, and 2014 PJM Load Forecasts (excluding EKPC and DEOK which joined after 2010).

Case Study: The PATH Project

The proposed Potomac-Appalachian Transmission Highline (PATH) transmission line is an example of a major investment that was delayed, and ultimately abandoned, because PJM Mid-Atlantic peak load was consistently overestimated. Although the annual peak load projection we discuss here is independent of an EE forecast (which was not incorporated by PJM planners), it demonstrates the effect that reduced peak load forecasts can have on costly transmission projects. The project was originally identified in 2007, with a year of need of 2012 for delivery of power to the Washington, DC and Baltimore region; the cost estimate of the project was $2.1 billion. However, the need for the project was continually delayed each year, based on the updated data in the annual RTEP.

During RTEP 2011, the project was temporarily suspended due to "reduced demand growth, increased demand resource commitments and new generation coming on-line" (Bruner 2012). Finally in 2012, the project was cancelled because "the reliability needs justifying development of the PATH project no longer exist throughout PJM's 15-year planning horizon" (Bruner 2012).

The cancellation of the PATH Project avoided $2 billion in transmission investment. However, the initial identification of need and subsequent delays meant that $121 million was already spent on planning the project before it was cancelled (Bruner 2012). Figure 9 shows the change in net peak load forecasts for the PJM Mid-Atlantic region from each RTEP year, and how this led to postponing the need for the project.

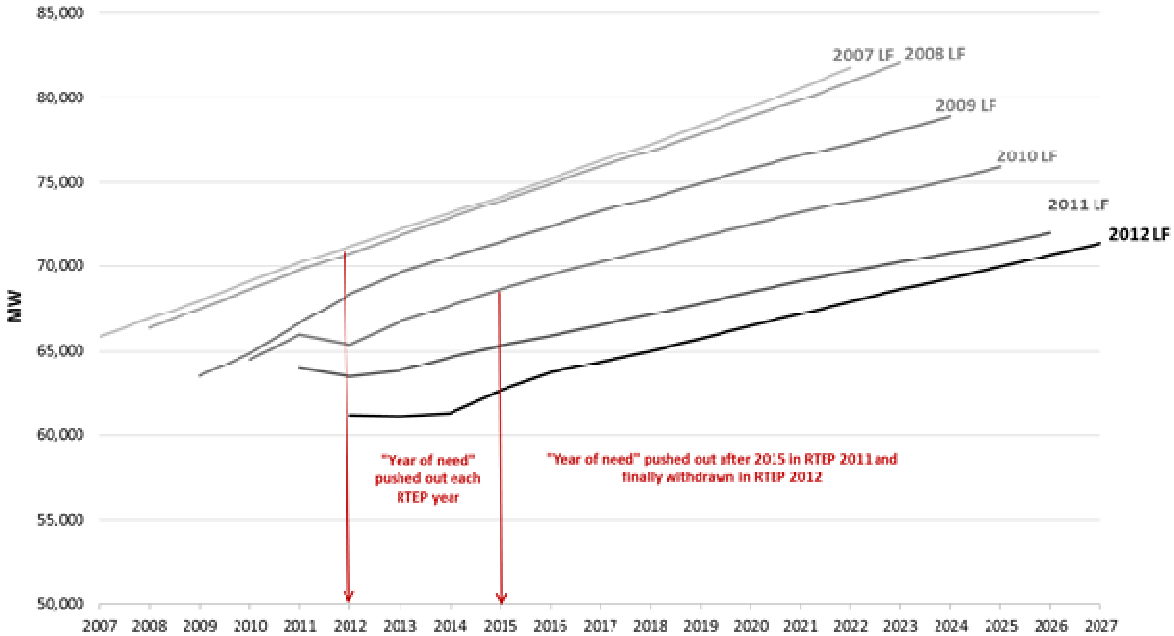

Figure 9. Impact of successive peak load forecasts on need for the PATH project.

Conclusions

By examining the forecasting methods and practices of two RTOs—ISO-NE and PJM—we have demonstrated the importance of accounting for EE impacts in the forecasts used for transmission planning. Comparing and contrasting forecasting practices and the use of EE forecast results at the two RTOs has indicated that more inclusive accounting for EE impacts in the regional load forecasts will defer or avoid transmission investments that are unnecessary, thereby saving ratepayers from paying for costly infrastructure investments that are not needed, or that could be spent on more useful projects. The corollary is that not accounting for EE impacts in the forecasts would likely result in the building of unnecessary transmission projects, with significant financial impacts. We have cited the $2.1 billion PATH project as one example of a project that was deferred after peak load forecasts were revised, albeit not due to the inclusion of an EE forecast. Based on our analysis, these findings appear to ring true for regions with Big EE, such as New England, and for regions with growing EE, such as the mid-Atlantic region of PJM. Therefore, once EE impacts become larger than the background noise in the load forecast, perhaps greater than 0.5% of retail sales annually, it is crucial to account for the EE impacts in all planning practices.

More RTOs are beginning to explore how to account for the EE impacts in their forecasts, and the RTO forecasting practices are evolving (for example, see Barbose et al. 2014). Yet the forecasting of EE costs and impacts by RTOs is still in its infancy, and best practices

have not yet emerged. The critical first step is to *do something* to account for the EE impacts, and to do such accounting over the time horizon addressed by the load forecast and associated plan. This paper demonstrates that there is a major financial risk of *not accounting for the EE impacts*, or even in just accounting for the near-term EE impacts (e.g., over a three-to-four year period of a forward capacity market, or for a short-term action plan)—since such a practice can result in an inaccurate forecast that could lead to costly investments that are not in the public interest.

Those regions that have not yet created an EE forecast should undergo the process of creating an initial methodology right away, and then improving it over time. New England has experience with this process. While some parties there have raised concerns about the specific methods used by ISO-NE in its EE forecast, including the discounting factors, stakeholders appreciate ISO-NE's initial efforts to account for EE in its load forecasts and transmission planning. These early efforts have led to deferred investments and significant cost savings for customers. While the EE forecasting methods are not perfect, and while the methods are expected to improve with the growing experience of ISO-NE's planners, accounting for the majority of the EE impacts in the early years of RTO efforts, even with some discounting, is far better than not accounting for EE impacts at all. More inclusive accounting of the largest portion of the total EE impacts has proven to be an important step forward for ISO-NE and the region. This is a case in which the perfect should not be the enemy of the good – and the good progress made to date has been both important and valuable.

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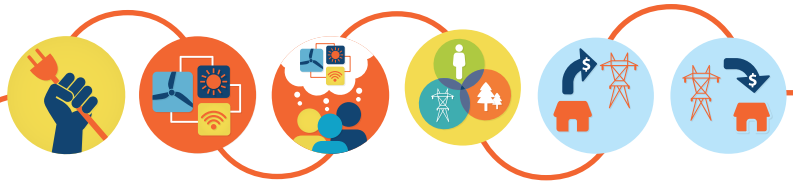
Acadia Center

UtilityVision



UtilityVision is a collection of resources for decision-makers and stakeholders, designed to outline the specific steps we can take to create an energy system that meets our energy needs and supports a fair, healthy economy and environment.

Acadia Center's EnergyVision (2014) presents an overarching framework to guide investment choices and reforms needed in our energy system. EnergyVision sets forth important steps on four parallel tracks to create an energy system that is safer, cleaner and more affordable, and offers the promise of deep reductions in greenhouse gas emissions: (i) utilize market-ready technologies to electrify buildings and transportation (ii) modernize the way we plan, manage, and invest in the power grid to facilitate consumer control and new technologies; (iii) make continued progress toward a clean electric supply; and (iv) maximize investments in energy efficiency to reduce unneeded energy demand that waste consumer dollars and act as a drag on the economy.

UtilityVision confronts a core part of this climate and energy future: how to construct a fully integrated, flexible, and low carbon energy and grid network. UtilityVision is a framework for how reforms in five interdependent categories can be aligned to put the consumer—our homes and business—at the center of a modern energy system and move us on the path to attain our climate, economic, and consumer goals. The interests of consumers and a sustainable energy system have merged more than ever before. UtilityVision offers a comprehensive pathway to a smart and dynamic electric system focused on giving consumers and communities greater freedom and control over their energy costs, managed with the cooperation of utilities, governed by updated regulations that honor energy technology change, supported by flourishing but well-regulated markets and providing a fair and safe system to protect consumers.

www.acadiacenter.org/document/utilityvision/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Center

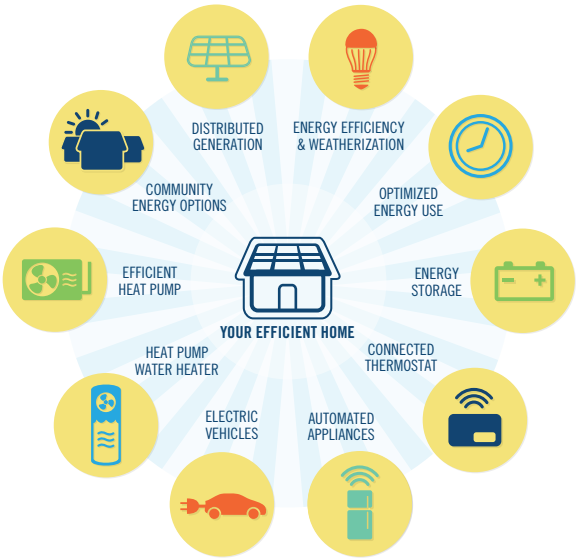
Empowering the Modern Energy Consumer

Today's electric grid is built around technologies that date back to the time of Thomas Edison. The grid—and the policies that govern it— are increasingly out-of-step with new technological advances and consumer expectations for a clean, affordable, resilient, and reliable energy system.

It is time for a cultural shift in how we think about the energy system. No longer should energy dollars be poured only into massive power stations and miles of wire. The energy system should empower people and connect communities in ways that maximize participation and minimize our energy burden and harmful environmental impacts. The old way of constructing the power grid is limited to traditional engineering approaches and is short on authentic consumer engagement that has the potential to deliver a cleaner, lower cost energy system and stronger communities.

In the new UtilityVision approach, more than poles and wires connect neighbors. The new energy system will bring energy efficiency into more homes, businesses and communities, creating local jobs that can't be outsourced and lowering energy bills. New energy technologies will be allowed to flourish so neighbors can connect through community solar arrays or district heating and cooling systems.

An advanced energy future isn't only about Teslas and Nest thermostats, either. Local energy projects can affordably meet the needs of municipalities, freeing up resources for education, public safety, and other critical services. We can reduce the impact of infrastructure in our neighborhoods by deploying customer-side energy resources like demand response and roof-top solar. Electric cars and city buses will reduce noise and diesel pollution in our streets, and the twenty-first century electric grid will embrace electric transportation in a manner that boosts system reliability, minimizes costs, and protects consumers. Renters will have the power to make energy choices for their homes and compare energy costs before they sign a lease. Communities can set and enforce a reasonable standard of efficiency to protect tenants from bearing the cost of overly expensive energy systems.



The modern energy system should benefit and empower all of us to control our energy use and costs, enable consumer-friendly, clean energy technologies to flourish, establish fair and non-burdensome rates, and ensure that consumers—especially the most vulnerable—are treated fairly in the new energy system. While UtilityVision describes a major shift in consumers' role in the energy system, the changes should be implemented strategically so that consumers have the information and understanding to make beneficial decisions.

UtilityVision's updated approach to energy regulation is based on overarching principles:

- *Coordinated planning for the future*: Grid planning will be comprehensive and proactive, merging traditional engineering and infrastructure solutions with customer-side, clean energy technologies.
- *Consumer protection and fair pricing for all*: The modern energy system will empower all consumers by allowing customer-side resources to flourish, establishing fair and non-burdensome rates and revenue structures, and providing a full safety net of necessary protections.
- *Updated roles for regulators, utilities and stakeholders*: Regulators will have a stronger role in strategic grid planning, aligning utility incentives with consumer and environmental goals, and ensuring that the consumer is at the center of the modern grid.

Strategic Planning for a Consumer-Focused Power Grid

Challenge:

Traditionally, utilities and regional grid planners focused on maintaining the power grid for one-way power flow from fossil-fuel power stations over miles of power lines to homes and businesses. Utilities used infrastructure and engineering tools like new circuits, new substations, new power lines, or larger conductors to support growing energy demand and maintain reliable service. Increasingly, cleaner and more cost-effective customer-side tools like energy efficiency, load control, distributed generation, and demand response can be used instead of—or in combination with—traditional infrastructure projects. But the old way of planning and paying for the grid effectively locks out consideration of these newer consumer- and environmentally-friendly solutions.

Recommendations:

Local Distribution Grid

- **New utility planning for a consumer-focused distribution grid:** Long-range grid planning must be comprehensive, merging the traditional world of "poles and wires" with new technologies and modern strategies. Comprehensive, multi-year Strategic Grid Plans should be required, and must:
    - Start with proactive planning to streamline consumer adoption of new energy technologies. Utilities should forecast adoption of customer-side energy resources and proactively plan more efficient and cost-effective upgrades at the local circuit level.
    - Compare a wide array of "grid-side tools" and "customer-side tools" to optimize the grid. The range of solutions considered should be broad and comprehensive: ranging from traditional "poles and wires" to new grid technologies like voltage management to customer energy efficiency, storage, and distributed generation.
    - Evaluate a range of options and scenarios on the basis of standard and level criteria, such as cost, benefits, risks, and public policy goals.
    - Pursue technological synergies.
    - Position the utility well for addressing emerging challenges, embracing new technologies, and continued innovation.
    - Identify an action plan to implement the plan over a multi-year period, implemented with on-going, independent evaluation and annual reporting to stakeholder advisory council and regulators.
- **Update cost-benefit calculations to reflect the public interest:** Decisions about the grid should be based on a calculation of cost-effectiveness that is aligned with state's consumer, energy, and environmental goals. Cost-benefit frameworks should be designed or expanded to fully reflect priorities such as reducing energy bills and reducing consumers' energy burden, addressing climate change, enhancing consumer control and choice, and system-wide efficiency.

- Customer-side resources and energy policies that reduce demand must be included in forecasts of energy consumption and peak demand.
- System needs should be identified, quantified, and described early enough to allow customer-side energy solutions to be proposed and evaluated.
- Customer-side energy resources should be eligible for the same payment treatment as traditional infrastructure solutions for reliability needs.
- Utility incentives should be reformed so that customer-side energy resources are seen as opportunities, and not competition for large, capital-intensive transmission projects.
- State regulators should require that customer-side energy resources are evaluated as part of any economic justification for new transmission system projects. Proposed transmission projects should demonstrate how the project will maintain safe and reliable service, support clean energy goals, and provide the most cost-effective option compared to competing alternatives.

Consumer Voices Critical to Energy System Planning:

Consumers do not only have to be the pocketbook of the grid; they are increasingly the focus of new energy innovations. Improving the consumer voice in energy grid decisions is critically important. A consumer stakeholder advisory council can provide meaningful input into utilities' long-term grid plans and ensure that consumer and environmental benefits are maximized. Structured stakeholder participation in the development and review of long-term grid plans can benefit grid modernization efforts in several ways:

- *Address the imbalance in resources and information* that can lead to utilities' disproportionate ability to influence regulatory decisions and result in the public perception of unfairness.
- *Achieve greater buy-in by all affected parties*, which can reduce the total time of making and implementing decisions. This reduces the regulatory burden and the potential for litigation or appeals of regulatory decisions.
- *Bringing together diverse interests to identify*, discuss, and address complex issues and provide recommendations. This helps overcome information gaps and assist regulators' evaluation of plans and policies.
- *Building a foundation of common knowledge* will lead to greater public acceptance. Actively engaging consumer, business, and environmental interests will ensure more balanced and stable outcomes—a process that has worked well in several states to advance energy efficiency investments and could be adopted and expanded.

- **Regulators have a stronger role in strategic grid planning:** Regulators must play an important role in ensuring that grid planning and utility investment decisions advance a modern, clean, and consumer-friendly energy system by connecting and aligning the utility business model, grid planning, and stakeholder participation.
- **Regulators have a critical role in ensuring consumer protection:** The current regulatory system provides numerous safeguards for consumers. These should be maintained and adequate protections extended to new or expanded retail markets for energy services and equipment so that market players operate in a fair, responsible, and consumer-friendly manner. Protections ranging from winter shut-off restrictions to licensing and code of conduct for companies that approach consumers are among the wide range of consumer protections needed.

Aligning Utility Incentives with Consumer and Environmental Goals

Challenge:

A common way for utilities to earn revenue is by making capital investments on which the utility earns a specified rate of return that is set by the regulators. This system gives utilities incentives to build or upgrade traditional infrastructure projects. This model is increasingly at odds with new technologies that can optimize the energy system and with public policy goals to increase energy efficiency and consumer adoption of distributed energy technologies. Utilities are reluctant to make proactive investments in the grid—such as upgrading circuits to connect more roof-top solar—or to deploy advanced metering or communication systems, because it is unclear whether these investments fit the criteria that determine whether the utility can recover its costs and return.

Recommendations:

The regulatory model needs to evolve to provide utilities with the appropriate financial incentives to encourage full and timely implementation of states' consumer and environmental goals. Instead of earning revenue primarily for building more infrastructure, utilities should also be rewarded for achieving energy efficiency and clean energy goals, minimizing the cost of the grid, and providing choices, opportunities, and control to consumers.

- **Implement Revenue Decoupling:** Revenue decoupling is a well-established rate-making mechanism that severs the link between a utility's sales and its profits. This reduces a utility's financial disincentive to invest in energy efficiency, distributed generation, or any initiative to reduce consumption. States should implement full revenue decoupling, and should not implement high fixed charges or straight-fixed variable rates that are erroneously considered as alternatives to decoupling.

- **Use Grid Planning to Set Rates:** The Strategic Grid Plans should be used to inform the amount of future revenues a utility is allowed to earn, which would then be used to set electricity rates. The Strategic Grid Plans should also be used to inform performance incentive mechanisms.

- **Adopt Performance Incentive Mechanisms and Standards:** Performance incentives mechanisms for utilities have been used for many years, and these can be refined to include emerging performance areas such as system efficiency, grid enhancements, energy efficiency, distributed generation and environmental goals. By increasing the portion of revenue requirements recovered through performance incentives, while reducing the portion of revenue requirements that a utility recovers from the rate base, performance incentive mechanisms help to shift the financial incentive away from capital investments and towards achieving performance goals. In the long run, states and regulators should consider transitioning away from reliance on rate base revenue and give consideration to using transition charges as the energy system moves and resizes to a distributed model.

    - States should establish performance standards to ensure that utility management is aligned with state energy policy, such as capturing all cost-effective energy efficiency and demand response resources. Cost-effectiveness standards should be defined broadly to include all relevant benefits.

- **Provide Regulatory Certainty:** Regulators and stakeholders should use the Strategic Grid Plans to provide the utility with up-front guidance with regard to future resources, grid enhancements, and major capital expenditures. This guidance should provide utilities with greater flexibility and incentive to adopt emerging and innovative technologies and practices.

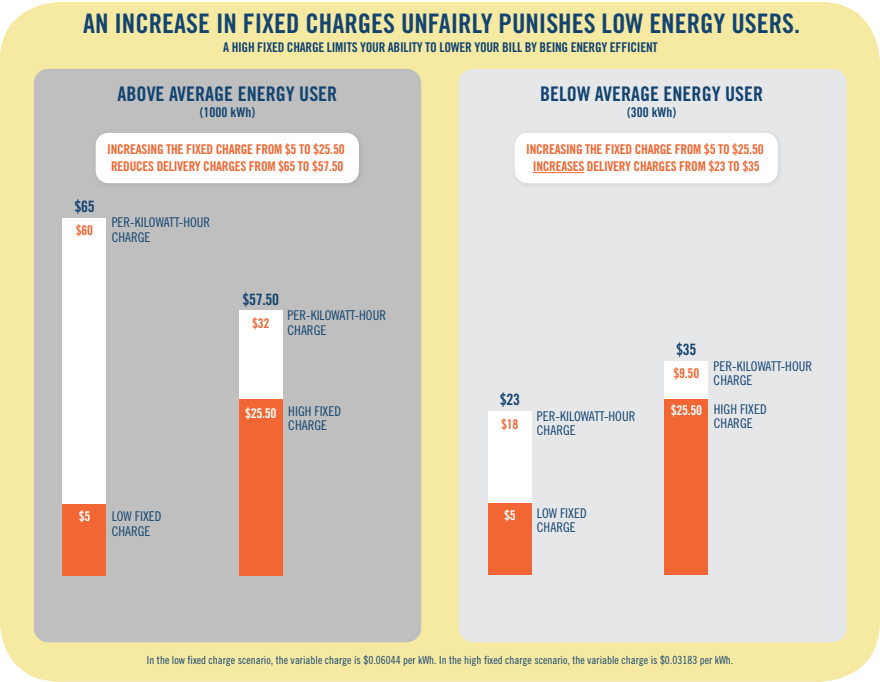
How Consumers Pay for the Power They Use

Challenge:

Despite the progress in clean and innovative energy options for consumers, current rate structures are outdated and do not allow sufficient freedom for new consumer choices. Most residential prices for electricity are flat: the same price per kilowatt hour any time of day or season. However, different portions of the electricity bill have different underlying cost structures. Energy supply costs are primarily influenced by the amount of electricity consumed and its timing because higher cost electricity generators operate when demand is high. In contrast, energy delivery costs, including transmission and distribution, are driven by infrastructure sizing for peak kW demand, often at a single hour during the year, at the regional and local levels. Our electricity bills should be designed to empower consumers to make smart energy and economic decisions, and preserve the consumer incentive to use electricity wisely.

Recommendations:

- **Avoid reliance on fixed charges, which limit consumer options:** High flat monthly charges make it harder to reduce electric bills by using less power or self-generating electricity. Fixed charges should be limited to the cost of keeping a customer connected to the grid, such as metering, billing, and data processing costs. The impacts of public policy considerations should be factored in, as well.



- **Move towards widespread time-varying rates for energy supply:** Time-varying rates provide better economic incentives to reduce overall generation costs and create opportunities for consumers to save money by taking advantage of low-cost hours. Time-varying rates come in a variety of forms, and as technology develops, consumers may be able to understand and benefit from more complex and granular options.

- **Align rates for energy delivery with real costs:** Both demand charges and time-varying rates are good options to consider to align rates for transmission and distribution with underlying system costs, while still creating opportunities for consumers to lower their energy bills through energy efficiency and other customer-side resources.

Demand Charges: Charges based on the actual costs to maintain the grid to deliver power when needed can reflect the cost a customer imposes on the grid during peak demand periods. Consumers with low energy use will generally pay a lower demand charge than bigger energy consumers. Well-designed demand charges, based on local or system peaks, can respond to customers' behavior in a timely way to reflect the benefits of efficiency, demand response, or other actions to reduce energy use.

Time-Varying Rates: Time-varying rates for energy delivery can be designed to approximate the incentives of well-designed demand charges. Customers would pay more for energy delivery at peak times when the system is constrained and less at times when the system has excess capacity.

Recommendations (continued...)

- **Align cross-subsidies with public policy objectives:** Market-based mechanisms can often be used to support consumer and environmental goals and reduce cross-subsidization (having one rate class support another). Some cross-subsidies exist to create a value that would otherwise be missed by pure markets, such as lower-cost power to low income customers. Regulators should ensure that beneficial cross-subsidies are aligned with state policy goals, while using market-mechanisms when possible to encourage economic decisions.

- **Phase-in rate innovations:** Significant rate innovations should be implemented on a phased and strategic schedule to ensure maximum consumer benefit and adoption. Consumers should be given time to fully understand the new rate system before it goes into effect. For example, time-varying rates may start as opt-in, transition to opt-out, before finally becoming mandatory. Clear information and education should be provided to allow consumers to understand their electricity bill and what actions they can take to reduce it.

- **Advanced metering infrastructure (AMI)**: AMI should be deployed when and where it is cost-effective. For example, AMI may be geographically targeted based on grid needs; rolled out based on customer size; or installed whenever old meters are retired. New residential rate classes can be created for customers with AMI, or for those who have high energy consumption. All customers could also be allowed to opt-into AMI and new rate structures.

  Costs, benefits, and consumer impacts must be evaluated throughout the phase-in. Keeping certain consumer segments, such as low income, on existing rate structures could be justified by both economics and consumer protection principles.

How Consumers Get Paid for the Power They Produce

Challenge:

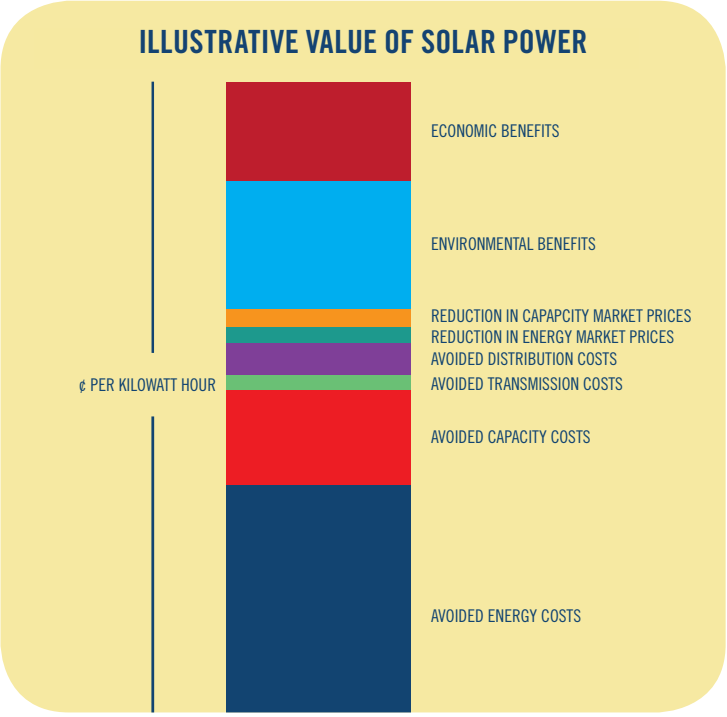
In many states, consumers with solar panels, wind turbines, or other power generation systems receive credits for excess electricity they provide to the grid when they generate more power than they need. In some cases, the customer pays the utility the retail rate for her net electricity consumption and gets credited at the retail rate for the power she sends back to the grid. The value of solar power—or wind power, or power stored in a battery or electric vehicle—however, is not necessarily the same as the retail price. It may be higher or lower depending on location, time of day and/or many other factors. Customers with distributed generation should pay the amount that reflects the costs of staying connected to the grid and get credited for the benefits they provide.

Recommendations:

In the long term, advanced metering and time-varying rate structures will make it possible to accurately charge and credit consumers for the grid services they use and provide. Until these innovations are widespread, regulators can set tariffs based on the calculated value of the benefits customer-side resources provide to the grid.

- **Short-Term–Use the right value for distributed generation:** Net output from distributed generation should be credited at a price that fully reflects its grid-wide costs and benefits, including environmental benefits and the value of avoided energy, capacity, transmission, and distribution costs, along with location value and other components where appropriate. Some jurisdictions are exploring or implementing, "value-of-solar" approaches and this methodology should be applied—and the right value calculated—for other distributed resources too.

Recommendations (continued...)



- **Long-Term- Align "how consumers pay" and "how consumers get paid:"** When the retail rates that we pay for energy supply reflect its time-and location- specific value, it will make economic sense to compensate distributed generation at the same rates. For example, it will cost more to use power on hot summer afternoons, and roof-top solar power will get compensated more for power it sends back to the grid because it is more valuable during those peak hours. Similar concepts apply to long-term reforms of energy delivery rates.

- **Meters that measure power flow in both directions:** Under a "bi-directional rates" approach, a distributed generation customer could receive a bill with the following components: 1) fixed charge (for metering and billing); 2) charge for power consumed on a time-varying basis; 3) credit for power exported on a time-varying basis; 4) charge for using the grid to consume power reflecting costs to the systems; and 5) charge for using the grid to export power reflecting benefits as well.

UtilityVision portrays a system that looks very different from the one we have today—one that would guide energy infrastructure investments and policies to a more consumer and technology—friendly, decentralized system that can put us on the path to achieving deep reductions in greenhouse gas emissions. UtilityVision sets forth a coherent path that ties the utility business model, rate-making, and customer-side energy resources together—offering a clear framework for stakeholders and regulators seeking to modernize the way we plan, manage, and invest in the power grid to empower consumers to have more control over their energy future.

Acadia Center is a non-profit, research and advocacy organization committed to advancing the clean energy future. Acadia Center is at the forefront of efforts to build clean, low-carbon, and consumer-friendly economies. Acadia Center's approach is characterized by reliable information, comprehensive advocacy and problem-solving through innovation and collaboration. UtilityVision was produced by Acadia Center staff, led by Abigail Anthony, Director, Grid Modernization and Utility Reform with primary contributions from Mark LeBel, Jamie Howland, and Daniel Sosland. Thanks to Synapse Energy Economics for their expertise and Public Displays of Affection for visualizations and design.

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The Old Order Changeth: Rewarding Utilities for Performance, Not Capital Investment

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ABSTRACT

It is time for jurisdictions serious about moving to a new utility model to transition from a rate-of-return structure to direct performance regulation. It will help utilities move to cleaner energy, energy efficiency, and their corollaries: customer-friendly and environmentally responsible service. Decoupling has reduced some barriers to pursuing efficiency, combined heat and power (CHP), and net metering. Although efficiency programs generally operate under some form of separate regulated performance structure, utilities still operate under traditional capital asset cost recovery regulation. As technologies and customer needs change, distribution utilities need to integrate new distributed resources into their supply mix by working in transparent partnership with customers and markets. This seismic shift will require a break from older models. It will require clear articulation of policy objectives by legislative and regulatory leaders, an active partnership in implementing, and an active learning process to translate those objectives into indicators that guide strong performance.

The authors outline a process that can help effect an intelligent transition. They address necessary preconditions for bringing it about. They discuss three essential tiers of utility performance incentives: (1) "guiding" incentives that set long-term goals and foster integration and coordination of services; (2) "directional" incentives, correlated to the guiding incentives, and (3) "operational" incentives, to assure customer service and reliability. The paper proposes three potential guiding incentives. It discusses how directional incentives could accelerate new capacity building for utilities, and how operational incentives can progressively improve customer service. High performance can result in increased utility effective rates of return.

Introduction

The *utility of the future* is now a buzzword in the utility industry. The term has been interpreted in many different ways but the essentials are simple: The dominant business model that has guided electric utilities is not facilitating the policy and technology changes that offer new, economically viable ways of operating in an increasingly diverse technology market.

It has long been recognized that the current framework of utility regulation—in which the utility's revenue is a function of its rate base (investment), multiplied by an allowed rate of return, plus recovery of prudently incurred operating expenses—is fundamentally flawed. It produces an incentive to invest, not an incentive to minimize costs or maximize value (Averch and Johnson 1962). Although evolving public policy has given the utility sector new missions, and changes in technology have given the utility sector (and customers) new tools, the basic framework of regulation remains largely unchanged.

It is tempting to respond to technology changes with "magical market thinking." But such an approach can open utilities and customers to new risks as regulatory protections are dismissed and technologies evolve and mature. "Markets" are simply too crude a tool to reach millions of

end use consumers whose electricity consumption amounts to only a small percent of their annual incomes.[1] Important roles exist for utilities and regulators, and for efficiency programs that offer strategic market intervention to overcome market barriers to efficiency. We need to shift our thinking to match the enormous shift that customers, technology players, and regulators are making, particularly as climate change increasingly drives us forward. Finding the pathway to a utility of the future that moves from providing electricity as a commodity to a structure that offers more sustainable energy security is the key. This can happen only if regulators and the industry directly connect revenue requirements and earnings to performance, not to expenditures.

We call this *performance-based regulation* (PBR; Lazar 2014). A PBR structure is something that could motivate utilities to move closer to becoming a utility of the future that serves customers equitably, meets their energy needs, and contributes to energy security. Lazar reiterates the longstanding position of the Regulatory Assistance Project (RAP): "…'all regulation is incentive regulation,' meaning that every framework for utility regulation provides incentives for specific behavior or specific outcomes, and those incentives guide behavior." (Lazar, 2014). This means, of course, that the default design of most regulated utility systems rewards capital investment and generally fails to put a premium on innovation and the development of services that offer long-term benefits.

The utility-of-the-future debate is dominated—if not clouded—by discussion of the functions the utility might perform, the services it might (or might not) offer, and how it would interact with new, market-based energy services. Of course, we must address these topics. But the debate often avoids the essential discussion of what regulatory incentive structure can guide incumbent utilities from "here to there." So, what is the pathway to incentivizing active engagement by utilities? Avoiding potential unintended consequences? Avoiding serious quality-of-service and reliability problems? Avoiding new forms of social inequity? And ensuring underlying financial viability?

There will have to be a transition, and it will have to involve enhancing customer empowerment and societal equity, and an improved environment. A dynamic, intelligent reward structure for utilities is critical to that process. This paper draws a roadmap for jurisdictions moving toward clean and equitable energy services to utility customers in a new era of technological opportunity and environmental urgency. We address the following topics:

1. The "next utility" structure and its incentive design should be informed by clearly articulated policy goals that guide the highest levels of decision-making.
2. The policy and regulatory framework must inform a new, emerging partnership between regulators and utilities, built on a shared vision of effective innovation and performance.
3. Solid implementation experience—in deep energy efficiency and "least-cost planning and procurement"—offers the right kind of platform for building a sound incentive structure for guiding "next utility" success.
4. For policy makers, a commitment to and experience with some form of revenue cap regulation should underlie the guidance on new incentive structures to utilities.

[1] Classical economics supports the notion that competition in markets leads to operational efficiency. But this occurs only when preconditions to efficiency under competition are met, such as goods that are a perfect substitute, perfect information on behalf of producers and consumers, free entry and exit, and fungible capital. None of these assumptions is present in the electricity industry, which is capital intensive with capital invested in specialized equipment. Electric utilities frequently act like natural monopolies, and are subject to being eroded by new entrants.

5. The process should be transparent, and sufficiently dynamic to welcome new forms of distributed resources and customer empowerment, but thoughtful about enhancing the underlying value of the distribution system.
6. Policy makers should outline a new performance structure early, and plan for incremental implementation. But they should also anticipate appropriate adjustments in response to well-structured feedback and assessment mechanisms.
7. Some jurisdictions will be able to use "collaborative" models to guide implementation of performance regulation through a shared, ongoing process.

The Role of Policy Goals in Allowing the Next Utility to Emerge

There is a practical value to articulating clear policy goals at the legislative and regulatory levels. Those goals will guide a wide range of planning and implementation actions over time. However obvious this may seem, it is not at all standard practice. Active policy guidance allows clear discussion and direct, efficient debate as implementation proceeds. If policy makers do not articulate an overarching policy direction, every decision about implementation becomes *both* an implementation discussion *and* a policy discussion. This leads to confusion, inefficiency, and potentially, paralysis.

As a positive example, Hawaii has a goal of achieving renewable energy production equal to 100 percent of its utility sales by 2045. This goal helps Hawaiian policy makers and utilities frame discussions of renewable energy as a matter of "how to," not "what if?" Decisions about how to integrate solar, efficiency, strategic electrification, storage, and demand response in Hawaii must be about successful integration and cost control, not about *whether* they should be pursued, or "how hard this will be to do." The path to effective integration is not obvious (nobody has done this, yet!) and it will be contentious. But the evolution from current rate-of-return utility incentive regulation to regulation based on the utility's performance in achieving defined goals has solid justification in policy. Active regulatory oversight and clearly expressed overarching policy that guides participation will be essential to effective transition into the "next utility" era.

Many of the policy goals guiding utility-of-the-future regulation are already in place in some jurisdictions. Such goals involve (1) securing all cost-effective efficiency; (2) actively addressing climate change; (3) decreasing risk and enhancing reliability by diversifying energy sources; (4) empowering and mobilizing customers and market actors by supporting distributed resource deployment; (5) providing economic and social equity, and health benefits; and (6) consistently considering "least-cost" energy use in all sectors (transportation and delivered fossil fuels, as well as electricity; and coordination with natural gas service).

Nevertheless, translating broad policy goals into practice takes time. Rhode Island passed its Least Cost Procurement legislation in 2006. The legislation led at first to a slow increase in the procurement of energy efficiency, but then the ramp-up was remarkable. Rhode Island did not pass legislation until 2010 that directed a revenue cap or "revenue decoupling" mechanism. That passage accelerated the pace of energy efficiency implementation. In 2015, the Rhode Island Collaborative (with the assistance of the Office of Energy Resources, National Grid, and the state's Energy Efficiency and Resource Management Council) created the Systems Integration Rhode Island (SIRI) group. It considers strategic electrification, demand response, the integration of least-cost principles into distribution system planning, and performance regulation for the utility (SIRI 2016). This emerging "system wide" discussion of future utility roles grows out of a strong collaborative approach to energy efficiency planning and

implementation that has expanded to include (for instance) consideration of how utility distribution system planning should respond to distributed resource development more broadly.

A Different Relationship (Partnership?) between Regulators and Utilities

One of the "advantages" of the current rate of return regulatory model is that it is at least familiar to regulators and utilities in terms of their expected roles. There are, of course, wide variations in the relative strength of regulators and utilities, and divergent perceptions of how "proactive" or "consumer-focused" regulators should be. There is also a familiarity in financial markets with "utility regulation" that offers a level of confidence for investors.

Abandoning rate-of-return regulation and adopting performance regulation has risks:

- Regulators won't know how to do it, and will have to think, investigate, and regulate in a new way to do it well. Risk of both over-regulation and under-regulation is significant.
- Utilities will strongly resist, and will try to game a new system to their advantage.
- Markets will perceive new risks and perceive higher investment risk.

These challenges are real, but they need to be understood in the current context. Utility markets are already changing. Climate change and new technologies are factors in issues of prudent investment, recoverability of costs, and whether customers will leave the system.

In effect, we are now asking explicitly that utilities facilitate expanded customer and market investment in meeting our energy needs. Regulators need to recognize that this is a new role for utilities, and respect that new risks will necessitate new skills and capabilities. Deliberate and thoughtful progress toward such a new partnership can create some new opportunities for utilities (electrification of the transportation sector). In can also create new investor confidence.

The Importance of Deep Commitment to Efficiency Planning and Implementation

It is clear that regulators need to work with utilities to encourage a transition to a performance-based structure that aligns utility interests with societal and environmental goals. It might not seem obvious that commitment to and planning and implementation experience with energy efficiency programs are strong precursors of viable performance regulation. But they are.[2]

The systematic pursuit of energy efficiency as a resource, and as a broader effort to transform markets, is not a marginal or adjunct strategy in the evolution to the utility of the future. Instead, it introduces a new way of meeting energy needs. Efficiency might be described as the "gateway drug" for distributed resource development. Energy efficiency is a service as much as it is a resource acquisition strategy. Investment in efficiency is significantly different from traditional distribution utility investment on behalf of customers. It requires the focus and skills that will also be required to integrate other distributed resources into the operation of the monopoly utility (Parker 2014). It is a different kind of investment strategy because:

[2] We acknowledge that there are many ways energy efficiency has been implemented, and there are several workable ways that efficiency capabilities can be acquired. Regulatory and utility commitment is the essential component. Independent providers working under separate regulation, or contractors working with utilities are available options to having the utility in the implementation lead itself.

- Historically it was the first step in recognizing customer investment in their facilities as a (partial) substitute for utility investment in traditional supply and delivery. Distributed generation, combined heat and power (CHP), zero energy buildings, and energy storage are other examples of a similar type of investment by "customers."
- Recognizing efficiency's potential reveals that massive energy improvements in buildings, customer-side resources, and market-based products and services will drive future energy provision. These investments can also mitigate climate change by driving reductions in greenhouse gas emissions. As understandable as this might seem, recognizing their importance creates a tension with traditional utility practice, which assumes that utility investment in ongoing generation, and in poles and wires, is the primary vehicle for meeting energy needs. Since efficiency is now an accepted feature of how we meet these needs, traditional utilities are no longer the "first choice" for providing energy services, nor do utilities stand alone in providing those services.
- Energy efficiency offers a new way of comparing options for meeting customer energy needs. These options compare lifetime costs and consider all associated costs and benefits of energy alternatives. We must extend these methods to guide investment in distributed resources if we are to maximize customer, system, and societal benefits. Utilities, regulators, and consumer advocates are now experienced in cost-effectiveness analysis, assuring the measures acquired actually reduce the costs ultimately borne by consumers.
- Efficiency implementation requires customer relationship skills, knowledge of markets, and broad technology expertise in end uses. These attributes are not "natural" to utilities.
- Many jurisdictions now recognize energy efficiency as a new tool for helping low-income populations—a way to offer social equity. Traditional regulatory practice tends to adjust rates for low-income customers to mitigate the disproportionate costs that energy services can impose on low-income customers. Efficiency strategies (and other distributed resource strategies) empower customers—both low-income and other customers—by providing access to affordable capital for projects that lower their energy costs. These strategies also provide long-term system and societal benefits rather than price distortions (Tong & Wellinghoff 2016).
- The role of energy efficiency (and distributed resource development) for low-income populations has particular urgency in light of the faith in "market solutions" eagerly espoused by many commentators on the utility of the future. Market solutions are likely to both undercut rate subsidies *and* offer heightened advantages to participants with ready access to capital. This version of the future could further marginalize low-income populations, which disproportionately need subsidies and access to capital.

Are New Energy Plans on Track to Creating the Utility of the Future?

In requiring new skills and capabilities by distribution, transmission, and supply entities in the regulated monopoly utility model, an effective utility of the future will depend on the quality of those skills in successfully planning and reconfiguring how they provide service. Even these skills are qualitatively different from the market and customer skills emerging from energy efficiency implementation. How will "next utility" skills be developed, and how will the customer and market skills—and the protections and market support inherent in them—be

preserved? And how will they be enhanced? These questions must be addressed at least in part through performance design, as a prerequisite for an effective transition to the next utility.

An interesting discussion of these issues has surfaced in New York's Reforming the Energy Vision (REV) initiative, which explores energy industry transitions. A recent paper on ratemaking and utility business models (NYDPS 2015) states:

> Unlike competitive companies whose long-term increase in profitability is driven by growing revenues and controlling costs, utilities' earnings are largely a function of increasing investment and controlling short-term expense.
>
> Placing the customers' interests in total bill management, including reliance on DER [distributed energy resources] at the center rather than the fringes of the utility's operating and business models, means that third-party and customer capital and market risk need to be added dimensions to how utilities meet their monopoly service functions. By allowing DER providers to contribute services and capital that result in greater value, innovation, and DER penetration onto the system, utilities' capital requirements and associated returns from traditional cost-of-service regulation may be reduced, and utilities will necessarily incur additional expenses to accommodate these changes.
>
> The conventional regulatory approach prevents the utility from profiting in the long term through the most efficient use of operating resources or through reliance on third-party capital contributions. If utility capital costs are the primary means to achieve utility earnings, then to the extent that market investments could displace utility investments, utilities will have a disincentive to encourage efficient market developments …
>
> It is critical therefore to eliminate, as much as possible, any structural financial incentive embedded in regulation for a utility to favor its own capital spending over third-party activity that meets system needs at lower cost to ratepayers.

The observation about the structure of utility incentives for innovation is on point. But in fact, the capabilities developed within utilities (where they are the implementing entity for efficiency) and within stand-alone energy efficiency utilities (EEUs) are exactly those that utilities need if they are to perform well in a utility-of-the-future market. These skills are producing tangible economic benefits and reducing utility risks. (Binz 2014)

Over the past 25 years, utilities *have* developed market and customer skills in their efficiency programs: technology evaluation, cost-effectiveness analysis, market assessment, program design, planning, effective relationship-building with customers and trade allies, marketing, market-driving strategies, and EM&V capabilities.

These capabilities have emerged through a utility's system benefits charge for efficiency programs usually tied to some form of performance incentive. Or these capabilities have evolved independently, with regulatory oversight, through the creation of an independent energy efficiency provider.[3] REV has ignored the role that efficiency implementation has had in

[3] Vermont spends $50 million a year for its statewide EEU, making it a very affordable investment in energy efficiency. That amount sustains investments in new knowledge, technology, and market capability that utilities have not had to invest in through increases in the cost of service. Other EEUs in Maine, Hawaii, Oregon, and the

assembling these capabilities. It further ignores the structure that has supported their development, and relegates energy efficiency to little more than a small role in the world of the traditional utility—or, at best, to a new level of implementation through the "magic" of the marketplace.[4] When it does discuss energy efficiency, REV is essentially blind to the option of efficiency's potential for *expanding* services to support customers in an integrated and comprehensive manner that would facilitate customer-focused market development and highly effective, integrated investment by customers. What REV does not appear to ask is: "What has New York learned from its substantial investment in energy efficiency, and how can it be adapted to incorporate the new market-focused opportunities before us?"

The second problematic component of the REV approach is that it leaps to a theoretical discussion of the new platforms utilities must create to mobilize market investment and participation. It then assumes that utilities will be able to earn a significant portion of their new revenues from a new "earnings" strategy adopted by regulated utilities. There is little evidence to support this strategy's viability in the energy utility sector (NYDPS 2015). **This shows where REV fails to link clear policy guidance to the design of utility incentive structure.** These market-based earnings (MBEs) are defined as *utility earnings derived from facilitating the creation and transaction of value-added services by active users of the [distributed system platform]* (NYDPS 2015). REV assumes that these new activities will involve sharing customer data (an alarming element for privacy advocates) and granting access to the new platform, as well as activities such as selling heat pumps and designing microgrids.

There is little to suggest that this approach will lead to the design of an effective performance incentive for utilities, guiding them to create a new market structure. In fact, it creates a *new* (and divergent) performance directive: "Make as much of your money as you can by doing these things." There are two serious dangers in this approach:

- **System risks.** There are inadequate incentives to ensure even minimal value to customers, let alone open system architecture and societal benefits. There is no serious discussion of how to design, approve, and regulate such activity. There is nothing to stop inappropriate use of market power. It could also lead to new financial risk for the utility. (What happens if these ventures lose money?)
- **Risk to customers.** There is no inherent emphasis on the customer benefit, product neutrality, and consumer protection built into well-run efficiency programs. The impartial, "trusted advisor" role is what customers and markets rely on to make their decisions in the marketplace. With less (or no) such support, customers might be led astray, and market participation might be temporarily misdirected and ultimately decline.

Are there new roles for distribution utilities at some point, and can they derive revenue from them? Likely, yes. But this will require a performance incentive structure that directs utilities to re-configure the distribution system; integrate distributed resources (including efficiency); and build a smart, dynamic, and interactive grid. Adapting a system benefits charge (whether listed separately on the bill or not) to pay for these activities during a transition, for

District of Columbia have proportionally similar budgets, and similar levels of effort exist for efficiency programs that are part of utility operations in Massachusetts, Connecticut, and Rhode Island.

[4] NYSERDA's evolution and the simultaneous decision by many utilities to design and run their own efficiency programs might have limited the recognition of the role that deep and aggressive efficiency efforts can play.

example, might be prudent. In fact, it might be time to consider the energy efficiency operation as a new performance-based, implementation entity, separately regulated.

Revenue Cap Regulation as a Foundation

Almost all leading energy efficiency jurisdictions have adopted some form of utility revenue decoupling. This approach, also known as *revenue cap regulation*, ensures that revenues will not be determined as a function of utility sales. It is an effective tool for removing a major utility disincentive to participate in efficiency, distributed generation, and CHP. It generally needs to be accompanied by measures that will prevent the distribution system operator from taking "…cost-cutting steps that will hurt reliability, safety, and customer satisfaction." For this reason, revenue cap regulation is properly paired with a service quality index mechanism, so that any diminishment of the quality of service will be penalized" (Lazar 2014).

Where revenue cap regulation is in place, energy efficiency is typically treated as a separate activity of the utility, funded through a system benefits charge on the customer's utility bill, with its own process for setting targets, evaluating performance, and rewarding success. This "separate but equal" treatment has resulted in considerable success in Connecticut, Massachusetts, Washington, California, and Rhode Island (for instance). In many such jurisdictions, the utilities' distribution system, supply procurement, and customer relations divisions have begun to recognize the capabilities and knowledge of the efficiency enterprise. But active partnerships are rare. Efficiency offers a modest revenue source, and the lost sales do not actively harm the parent company's net income. This is largely the case in Vermont, Maine, Hawaii, and in Oregon, where the independent EEUs means that the efficiency-related skills are not embedded in the utility and the partnerships to deliver effective service can evolve more effectively across utility boundaries. The increasing interaction between deep efficiency implementation and the pressures on utilities from emerging distributed resource opportunities and mandates create the nexus for the next step in the design of utility performance regulation.

The goal is to reward the utility for actively partnering with the needed customer and market-facilitating functions (whether internal or external to the utility) in a way that maximizes system and societal benefits, while avoiding an expansion of utility monopoly / market control.

The Policy Framework Should Be Dynamic and Open, but Recognize the Value of the Current System

Designing a performance incentive structure can be a little like using the three wishes granted by a genie. The wishes (and the incentive designs) need to be very carefully crafted. Poor design will lead to poor results, as shown by the many examples of experimental mechanisms that have failed to produce desired results (Lazar 2006).

A sound approach will recognize the old model, understand its limitations and distortions, and recognize what it does well in offering reliable, appropriate core services. Such an approach can articulate and promote positive intermediate objectives such as better distribution system use, better voltage control and lower line losses, and better acquisition and effective management of customer energy use (and customer empowerment) information.

Policy can drive specific objectives to be attained by a performance-based regulatory system ("We need to maximize the inclusion of clean, distributed generation to meet our climate goals"). Objectives can also emerge from challenges and opportunities confronting utilities and

regulators, as new mandates and technologies enter the market at accelerating rates ("We have net metering; how are we going to incorporate high levels of distributed generation that might be creating capacity problems on certain feeders?") The "crisis of success" of net metering can best be addressed by steady movement to a performance-based incentive structure that rewards effective integration. The best outcomes will happen when the discussion of the immediate challenge can be considered in the context of the policy objective. The result might be a plan for how the utility could be rewarded for supporting high levels of integration of distributed generation in a manner that enhances reliability, significantly improves the carbon profile of the utility, and supports long-term energy affordability for all customers. The following are examples of dynamic tension between policy objectives and significant technical, financial, and regulatory challenges that performance regulation should be designed to address:

- How can regulators motivate utilities to plan the distribution system from the ground up (rather than reactively), to maximize inclusion of and benefits from efficiency, distributed generation, and demand response?
- Will regulators be able to respond quickly to support flexible and appropriate responses to market changes that challenge the typical regulatory approach and timeline?
- If a primary goal is driving policy, how do regulators work with governors and regional or federal entities in setting efficiency and renewable energy standards that are subject to distribution system planning? For example, how can goal-driven DER activity be coordinated with changing market trends in energy storage and efficient products?
- Is conservation voltage regulation (CVR) a traditional efficiency measure? It is not typically a part of energy efficiency portfolios because its implementation is a function of managing distribution systems, not efficiency markets. CVR should be attractive to utilities because it reduces generation requirements without reducing sales, and reduces expenses without reducing revenues. Even so, it is not common utility practice.
- How do we preserve utility access to affordable capital to adapt transmission and distribution systems when utilities choose to show less capital investment is necessary?
- Should automatic adjustments and tracking continue to be separately calculated in utility tariffs, or should all costs be consolidated into a single, easier-to-understand retail rate?
- How can policy makers reward appropriate investment in systems that facilitate a new and accessible utility system (AMI, and other "intelligent system" functions), while ensuring that they are used effectively, rather than encouraging an approach that simply rewards utility investment as the "default" strategy?
- How can jurisdictions create a platform that facilitates and guides customer and market investments, while still ensuring (and maybe enhancing) reliability and system performance, without full ownership and control by the utility?
- How will cross-sector choices be made consistently and fairly? How should costs and benefits be assessed? For example, how can we design a system that helps fuel switching, natural gas, new energy uses, and CHP to support higher solar saturation?
- How will a utility be rewarded for appropriate investment in control technology to achieve effective load and demand management at regional, system, sub-transmission, and feeder levels?
- How will the utility acquire the skills to design and operate the emerging system?

- What will be the basis for gauging the level of utility return? This is currently the rate base, but phasing away from it will mean the reward from building the rate base will no longer drive decisions.

Start with a Noble Design, and Revise It as You Build

It might be helpful to start with a system based on a rate of return on equity and recovery of allowed costs, with attainable adders for (1) maintaining reliable service and (2) attaining intermediate objectives (via AMI adoption, effective demand response, improved planning, integration of distributed resources.) This implies adopting a new, lower allowed return with potential adders for performance in relation to specific indicators. Such a strategy will ensure the utility must prove it has achieved something beneficial to obtain a fair overall rate of return.

Regulators will then need to establish long-range performance incentives that specify at least three overarching and multi-year objectives tied to a major portion of future performance reward. These goals should be phased in across three to five years, at which point utility rates would be set to cover the interest on debt instruments associated with the cost of capital, but offer no built-in rate of return on utility equity. They would be designed such that the utility could earn slightly above a traditional allowed return on equity if they perform well.

Three hypothetical examples of the overarching indicators are:

1. **A cost-per-unit-used indicator**. This indicator could calculate the "blended cost" of energy. The calculation would involve what are considered distribution costs and traditional supply commodity costs. It would also include in-service efficiency measures provided on an equal footing with the first two.[5] Since efficiency generally has a significantly lower lifetime cost and less variability than most supply options, it would be useful to the utility for driving down average costs. This requires a different framework from one that measures "average cost," since the numerator includes supply side and demand side resource costs and customer-sited generating resource costs. The denominator would be the sum of delivered energy, site-produced energy, and saved energy. This indicator would help the utility support cost-effective efficiency and customer-sited generation. It would also reward utility support for demand response, CVR, smart evolution of the grid, and effective deployment of storage and demand response that could lower supply portfolio costs. It can encourage utility investments in promoting financing strategies that do not disadvantage low-income populations (Tong & Wellinghoff 2016).
2. **A carbon indicator.** This indicator could look at a "carbon-intensity-per-unit" of energy delivered, for example. It can apply to the conventional supply portfolio, to all efficiency currently in service, and would include the ability to track and reward displacement of fossil fuel through beneficial electrification (based on relative carbon profiles). It would include distributed generation on the system and a way might be found to include storage. This indicator would serve to balance the pressure from Indicator 1 to move only to "cheap" carbon sources when they were available.
3. **A "customer equity" or "customer empowerment" indicator.** This should assess the energy burden of customers, particularly customers in the bottom economic

[5] The cost of these efficiency resources should be based on a full societal test, with the cost of efficiency derived from costs attributable to energy saved, and other costs attributed to other benefits.

quartile (Teller-Elsberg et al. 2014). As noted earlier, the new utility model runs the risk of ignoring the needs of vulnerable customers (Tong and Wellinghoff 2016). The old rate subsidy strategies added costs and sent incorrect price signals. A new utility structure could empower all—and especially low-income—customers to reduce their energy use and bills. Deep efficiency, access to renewables, and participation in demand response would all be high priorities. An indicator such as household energy burden could be the basis for new incentive structures. Incentive designs would need to reward strategic assistance in access to capital for these customers.

A Collaborative Approach Might Facilitate the Evolution

Collaboration is a long-standing successful strategy for creating and overseeing utility energy efficiency (Li and Bryson 2015). It allows regulators, state energy offices, utilities, and customer and advocacy groups to participate in active oversight and regulatory input in matters that benefit more from negotiation than from exhaustive litigation. A collaborative to facilitate the transition must be guided by a clear policy framework as already discussed in this paper. It would also need sufficient, independent expertise to assess options for regulatory evolution and the viability of performance structures, and to document actual performance.

- It should test the feasibility of new strategies and new interactions with customers.
- It might use incremental incentive structures as knowledge is gained (cost recovery for pilots), cash incentives for meeting very preliminary targets, and then escalate performance incentives for effective ramp-up of target capabilities.
- Overarching goals should be tied to preliminary structure and tracking mechanisms. Initially they should be treated as a "scorecard," but as incentive design and effective tracking emerge, they should increasingly be within the utility incentive reward structure.

Conclusions

For jurisdictions that are serious about building a new utility model, the notion of a utility rate-of-return base tying earnings to investment levels must be replaced by a system that ties earnings to performance. It should not be tied to either kilowatt-hour sales or utility investment.

Even with a clear policy framework, it is not simple to re-design the utility structure and its underlying and original purpose. On the other hand, with jurisdictions that decide to pursue performance regulation, a lack of clear policy guidance is very likely to thwart positive results.

There is important learning about new regulatory structures through the introduction of energy efficiency programs and through the major shift associated with introduction of retail choice. Regulatory experience that can drive these kinds of policy-guided transitions will need to be built upon and expanded in the transition to performance regulation.

Least-cost procurement has facilitated strategies for "public good" investment in energy efficiency. It has also resulted in utilities' acquiring new skills in addressing market barriers, and interacting with markets and customers. These are not traditional utility capabilities, but they presage a critical component of what the utility of the future might look like. Utilities will need access to these skills, either internally, or through partnerships.

Some proposals for evolution to the utility of the future might inappropriately extend the monopoly power of utilities by seeking to create new revenue streams through privileged market knowledge and relationships of the utilities.

Revenue cap regulation will be a critical basic layer of rate regulation that enables movement to a broader, performance regulation platform.

The challenges for regulators and the risks for consumers are significant. Broad policy goals will guide effective regulation, but to achieve a steady, minimally disruptive transition to a new system, a thoughtful, evolutionary process will be needed. Where utilities have demonstrated good-faith commitment to developing customer-first services, there is likely to be a good opportunity to move forward constructively.

An important discipline for advocates, utilities, and regulators will be to identify where a technical issue is also a policy issue, and an incentive design opportunity. The regulatory system should also consider issues in relation to the long-term goals for the energy system.

The performance structure should start with tiered incentive indicators, to be phased in over time, and revised as experience and learning are gained.

In some jurisdictions a collaborative approach to managing the transition can provide an important forum for addressing complex issues, proposing new solutions, and for providing constructive input to regulators.

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RAP Energy solutions for a changing world

Smart Rate Design

For a Smart Future

Authors
Jim Lazar and Wilson Gonzalez

July 2015

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July 2015

Smart Rate Design for a Smart Future

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Acronyms

AMI	Advanced metering infrastructure
CP	Coincident peak
CPP	Critical peak pricing
CRES	Competitive retail electric service
DER	Distributed energy resources
DG	Distributed generation
DR	Demand response
EV	Electric vehicle
FIT	Feed-in tariff
IDGP	Integrated distribution grid planning
IRP	Integrated resource planning
kW	Kilowatt
kWh	Kilowatt-hour
LADWP	Los Angeles Department of Water and Power
LMP	Locational marginal pricing
MDMS	Meter data management system
NCP	Non-coincident peak
NEISO	New England Independent System Operator
NEM	Net energy metering
O&M	Operations and maintenance
PBR	Performance-based regulation
PTR	Peak-time rebate
PURPA	Public Utilities Regulatory Policies Act
PV	Photovoltaic
REC	Renewable energy certificate
RPS	Renewable portfolio standards
RTP	Real-time pricing
SCADA	Supervisory control and data acquisition
SFV	Straight fixed/variable
SMUD	Sacramento Municipal Utility District
SSO	Standard service offer
T&D	Transmission and distribution
TOU	Time-of-use
VAR	Volt-ampere reactive
VOST	Value of solar tariff

Executive Summary

Introduction

For most of its history, the electric utility industry saw little change in the economic and physical operating characteristics of the electric system. Though the system provided reliable and low-cost service, little in terms of system status or customer use was known in real or near real time. For an industry in the information age, parts of the electric system can be considered rather "unenlightened."

Current advancements in technology will have marked impact on current and future rate designs. First, end-users (i.e., customers) are installing their own generation, mostly in the form of photovoltaic (PV) systems, and are connecting different types of end-use appliances with increasing "intelligence" built in; electric vehicles (EVs), too, are poised to grow rapidly as a whole new class of end-use, just as storage systems are poised to become economic. Second, utilities are deploying advanced metering and associated data systems, sometimes referred to as advanced metering infrastructure (AMI) or smart meters, and more sophisticated supervisory control and data acquisition (SCADA) systems to monitor system operations. To realize the full potential of these new systems and end-uses, regulators, utilities, third-party service providers, and customers will need to utilize more advanced rate designs than they have in the past.

Rate design is the regulatory term used to describe the pricing structure reflected in customer bills and used by electric utilities in the United States. Rate design is not only the itemized prices set forth in tariffs; it is also the underlying theory and process used to derive those prices. Rate design is important because the *structure* of prices — that is, the form and periodicity of prices for the various services offered by a regulated company — has a profound impact on the choices made by customers, utilities, and other electric market participants. The structure of rate designs and the prices set by these designs can either encourage or discourage usage at certain times of the day, for example, which in turn affects resource development and utilization choices. It can also affect the amount of electricity customers consume and their attention to conservation. These choices then have indirect consequences in terms of total costs and benefits to society, environmental and health impacts, and the overall economy.[1]

Rate design is important because the *structure* of prices — that is, the form and periodicity of prices for the various services offered by a regulated company — has a profound impact on the choices made by customers, utilities, and other electric market participants.

Despite its critical importance, rate design is poorly understood by the general public and often lacks transparency. The difference between a progressive and regressive design can have a large effect — 15 percent by one estimate, but it could be more — on customer usage.[2] Traditional rate designs, which charge a single rate per unit of consumption (or worse, lower that rate as consumption increases) may not serve consumers or society best. As advancements in technology and customer preferences evolve, the industry must adapt to change or risk the fate of landline telephone companies, which have lost 60 percent of their access lines since the advent of telecommunications competition.[3]

Rate design relies in strong measure upon the judicious application of certain economic guidelines. The following

1 Weston, F. (2000). *Charging for Distribution Utility Services: Issues in Rate Design.* Montpelier, VT: The Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/412

2 Lazar, J. (2013). *Rate Design Where Advanced Metering Infrastructure Has Not Been Fully Deployed.* Montpelier, VT: The Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/6516. Appendix A provides a calculation of how rate design can influence consumption.

3 Federal Communications Commission (2014, October). *Local Telephone Competition Report*, available at: https://www.fcc.gov/encyclopedia/local-telephone-competition-reports

elements of economically efficient rate design that are necessary to address current and coming challenges in the electric industry are based on those laid out in James Bonbright's 1961 *Principles of Public Utility Rates,* and in Garfield and Lovejoy's 1964 *Public Utility Economics.* These principles require that rates should:

- Be forward-looking and reflect long-run marginal costs;
- Focus on the usage components of service, which are the most cost- and price-sensitive;
- Be simple and understandable;
- Recover system costs in proportion to how much electricity consumers use, and when they use it;
- Give consumers appropriate information and the opportunity to respond by adjusting usage; and
- Where possible, be temporally and geographically dynamic.[4]

Rates can be designed to meet (or, in the case of poor rate design, frustrate) public policy objectives to use electricity more efficiently, meet environmental goals, and minimize adverse social impacts, including public health, among others. They are also pivotal in providing utilities the opportunity to recover their authorized revenue requirement. Revenue adequacy is a core objective of rate design, but the more constructive design ideal for rates is forward-looking, so that future investment decisions by the utility and by customers can be harmonized.

Based on these historical works, and looking forward to a world with high levels of energy efficiency, distributed generation (DG), and customer options for onsite backup supply, the following three fundamental principles should be considered for modern rate design:

- *Principle 1:* A customer should be able to connect to the grid for no more than the cost of connecting to the grid.
- *Principle 2:* Customers should pay for grid services and power supply in proportion to how much they use these services and how much power they consume.
- *Principle 3:* Customers who supply power to the grid should be fairly compensated for the full value of the power they supply.

Principles for Modern Rate Design

- **Principle 1:** A customer should be able to connect to the grid for no more than the cost of connecting to the grid.
- **Principle 2:** Customers should pay for grid services and power supply in proportion to how much they use these services and how much power they consume.
- **Principle 3:** Customers who supply power to the grid should be fairly compensated for the full value of the power they supply.

These principles and priorities should be reflected in smarter rates designed to maximize the value of technology innovations, open up new markets, and accommodate the distribution and diversification of customer-sited generation resources. This necessarily includes consideration of what those future technologies and policies could look like, with a focus on metering and billing, market structure, and pricing. In particular, rate design should provide a "price signal" to customers, utilities, and other market participants to inform their consumption and investment decisions regarding energy efficiency, demand response (DR), and DG, collectively referred to as distributed energy resources (DER). **Bidirectional, time-sensitive prices that more accurately reflect costs most closely align with the principles of modern rate design.**

Challenges in Utility Rate Design

Over the last two decades, federal, state, and local policymakers have implemented policies that have spurred the development of customer-sited DG, in particular customer-sited PV systems. The policies range from federal tax credits to state renewable portfolio standards, Net energy metering (NEM), and interconnection standards.[5]

As the costs of renewable and other DG technologies — wind turbines, small hydro, biomass, and others — have decreased, the options available to customers to procure these technologies have increased. In addition, DG systems are decentralized, modular, and more flexible technologies that are located close to the load they serve. Customers can typically purchase or lease the DG from a third party, often

4 Lazar, 2013, p. 10.

5 Steward, D., & Doris, E. (2014, November). *The Effect of State Policy Suites on the Development of Solar Markets.* NREL. See also the Energy Department's SunShot Initiative, which is a national effort to make solar energy cost-competitive with traditional energy sources by the end of the decade. Through SunShot, the Energy Department supports private companies, universities, and national laboratories working to drive down the cost of solar electricity to $0.06 per kilowatt-hour. Learn more at: http://www.energy.gov/sunshot.

with seller or third-party financing. The increasing amounts of DG are impacting the delivery method of energy, and in the future may gradually shift from an exclusively centralized source of power, such as coal, nuclear, or natural gas-fired plants, to a mix of centralized and decentralized, smaller, and customer-centric sources of energy. Rate design must efficiently and fairly incorporate DG contributions to the grid, as well as fairly allocate the benefits and costs of their use for DG customers, non-DG customers, and for the grid.

At low levels of installation of distributed renewables (e.g., under five percent of customers), few if any physical modifications are required to electric distribution systems.[6] The scenario changes once solar output exceeds total load on a given substation. This is being experienced in Hawaii, which has the highest PV penetration of any state and where more than ten percent of residential consumers have PV systems installed. Installation rates are more than twenty percent in many single-family residential neighborhoods. At this level of solar saturation, changes to distribution systems may be needed. Hawaii is serving as a laboratory as it adapts to a high-renewable environment, and this paper explores the various adaptations that this state and many other jurisdictions are exploring and implementing.

In addition to increasing penetrations of distributed renewables, other technologies that will increase in the near future will need to be considered by utilities and regulators as they navigate the changing electric system landscape. EVs are a small part of the electricity load currently, but growth in the sector is likely for many reasons — lower battery costs and emissions regulations that are pressuring the industry to find zero-emissions transportation solutions.[7] Because of the presence of batteries in the vehicles and the ability to control the timing of when they are charged, EV loads can be very different from traditional loads. Encouraging behavior that optimizes EVs' use of the grid requires that rates be designed to provide an incentive for EV owners to charge their cars at the right time. This requires time-sensitive pricing, a topic this paper explores in detail.

Interfacing with **microgrids** will be another near-future challenge for utilities. These may range from an individual apartment building or office complex with onsite generation to a municipal electric utility connected to an adjacent larger utility. These will depend on utilities for some service, and compensation to utilities is important; however, microgrids will also provide services to utilities at times, so the compensation framework needs to be bidirectional.

Storage technologies such as Tesla's new Powerwall battery could be a game changer if they can be distributed in communities, interconnected with a smart grid, and not be price-prohibitive.[8] Currently, energy supply (generation) and loads (end-uses) must be instantaneously kept in balance, even as customers change their end-uses. But the presence of significant storage on the system would allow generators to generate when they can, while allowing the storage technology to provide additional energy or absorb additional energy as loads change.

The presence of generation, storage, and smart control technologies at customer premises offers the opportunity for customers to provide a number of valuable functions to the grid. These generally fall into a category termed **"ancillary services"** and include voltage regulation, power factor control, frequency control, and spinning reserves.[9] Where system operators or third-party aggregators have the ability to control end-use loads, customer appliances can deliver DR during high cost periods or when the grid is at or near its operating capacity and may be at risk for system failures. Rate design can either enable these values to be garnered or erect barriers to them.

6 Hawaiian Electric Company, with 11-percent PV saturation, is just now beginning to invest in distribution system modifications to adapt to high levels of solar energy. See: Hawaiian Electric Company Distributed Generation Interconnection Plan. (2014).

7 MJ Bradley & Associates. (2013). *Electric Vehicle Grid Integration in the US, Europe, and China.* Montpelier, VT: The Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/6645

8 "Storage" involves a series of acts: converting grid-interconnected electricity to another form of energy, holding that other form of energy for future use, and then either using it in the form stored (thermal or mechanical energy) or converting it back to grid-interconnected electricity at a different time. The individual acts that comprise this series may be referenced as, respectively, "charging," "holding," and "discharging." Pomper, D. (2011, June). *Electric Storage: Technologies and Regulation.* NRRI, p 3. To this should be added other forms of energy storage, such as water heater controls, water system reservoir management, and air conditioning thermal storage, which may provide lower cost means to shape loads to resources and resources to loads.

9 Spinning reserves refer to the availability of additional generating resources that can be called upon within a very short period of time. Different utilities and different utility markets use varying response time frames to define spinning reserve services, ranging from instantaneous to up to an hour or so.

Sustainable Rate Design

Near-Term Consumer-Friendly Reforms for a Clean Energy Future

November 9, 2016

Tensions in the Status Quo Due to Electricity Rate Design

Electricity bills for residential customers in many states often combine a low fixed monthly charge with flat rates for electricity consumed and delivered charged on a per-kilowatt hour basis. Traditionally, this structure has worked for utilities by providing a simple mechanism to recover enough revenue to build, maintain, and operate the grid. This rate structure also promotes investments in energy efficiency and protects low-income customers. More recently, retail rate net metering and credit rollover has become a simple and popular method for compensating customers with clean distributed generation.

This existing rate design for residential customers has many positive features, but is a blunt and inefficient instrument in many respects. Changes in electricity rate design can help address a number of different issues, but rate design reforms may be necessary to address two issues in particular: (1) inadequate incentives for customers to help manage the cost of infrastructure driven by local and regional peak electricity demand and (2) potential under-recovery of distribution system costs from customers with distributed generation who typically still use the grid for deliveries at many times during the month.[1] The latter challenge, which requires utility-by-utility analysis, will likely grow over time as more and more consumers invest in low-cost, clean distributed generation.

Transitioning to Sustainable Rate Design

Acadia Center's UtilityVision outlines comprehensive long-term rate reforms to align the way consumers pay for delivered power and how consumers get credited for power and services that they provide to the grid. These reforms would improve incentives for energy efficiency and distributed generation, preserve equitable access to clean energy, maintain protection of low-income ratepayers, and reflect equitable recovery of costs for use of the distribution grid. However, implementation of these long-term reforms will require advanced metering, energy management technology that is affordable for small customers, and significant customer education efforts.

In the shorter term, simpler steps can be taken but they must be consistent with three principles:

- Monthly customer charges should be no higher than the cost of keeping a customer connected to the grid and related customer service;
- Other components of electricity rates can be reformed to align customer incentives with cost drivers and the value customers can provide to the electric system; and
- Ratepayers must be able to understand significant reforms and have a basis on which to respond and manage bills.

These modern rate design principles are in addition to traditional rate design principles that include:

- Simplicity, understandability, and feasibility;
- Effectiveness at yielding revenue requirements, revenue stability, and rate stability;
- Fairness in apportionment of costs and avoidance of undue discrimination; and
- Efficiency in discouraging wasteful use.

[1] Concerns about cross-subsidies to DG customers must take into account the full range of costs and benefits.

Five Point Plan for Near-Term Reforms

Acadia Center proposes the following five-point plan to achieve the above described objectives and principles for residential customers:

- 1. Limit reliance on fixed monthly customer charges.
    - Fixed customer charges should be capped at cost of connecting the customer to the distribution system (typically around $5-10 per month[2]), including metering, billing, service drop and elements of customer service.
    - The full costs of advanced metering infrastructure (AMI) should not be included in fixed customer charges because AMI provides energy services beyond the cost of connecting a customer.
- 2. Implement Acadia Center's Distribution Reliability Charge ("DRC") and other components of rates would continue to be charged on traditional per-kWh basis as default.
    - The Distribution Reliability Charge would begin to account for distribution system costs that cannot be avoided by distributed energy resources. Details in separate DRC piece.
- 3. Offer opt-in time-of-use rates for energy supply.
    - Higher costs of consumption for on-peak periods and cost of capacity should be recovered from limited time periods, either seasonally or year-round.
    - Net metering credits for energy supply should be set equal to the time-varying rates, since they will be set at the value of the generation.
- 4. Enable or maintain virtual net metering for community distributed generation, with a robust low-income component.
    - Virtual net metering (also referred to as remote net metering or net metering credit allocation) is the key mechanism to enable community distributed generation.
    - These policies are critical to equitably sharing the benefits of renewables policies with low-income ratepayers and customers who cannot site DG at their home or business.
- 5. Begin to align net metering credits with ratepayer value and remove caps on net metering.
    - Acadia Center's Next Generation Solar Framework provides specific short-term recommendations for administratively adjusting net metering credit values to reflect the costs and benefits of solar and other non-dispatchable DG.
    - Value-based frameworks address ratepayer concerns about cross-subsidies and eliminate the need for net metering caps.
    - Monetary crediting (defined in dollars), instead of volumetric crediting (defined in kWh), is necessary to implement value-based approaches.
    - New structures can be phased in over time and existing projects can be grandfathered under current frameworks.

Next Steps

Many elements of the above five-point plan require further refinements and scoping of impacts on ratepayers and overall incentives for energy efficiency and clean local generation. Implementation will further require high-quality regulatory-grade analysis, with robust processes for stakeholder review and feedback.

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[2] Lazar, J. and Gonzalez, W. (2015). *Smart Rate Design for a Smart Future*, p. 36. Montpelier, VT: Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/7680

Frequently Asked Questions

What are the goals and impacts of these reforms?

As discussed on page one, this package of proposals is designed to simultaneously meet all of the rate design principles while also achieving a wide range of public policy goals. In addition to these principles and goals, we expect that the combined package would have the following effects:

- DG customers make an additional contribution to the embedded costs of the distribution system based on their imports. When combined with opt-in time-of-use energy supply rates, this begins to provide incentives for these customers to install energy storage and manage imports and exports;
- Customers with flexible loads (such as electric vehicles) have incentives to adopt time-of-use rates and consume less electricity at expensive peak times and more at times when there is extra capacity in the system;
- These reforms jointly promote equity by maintaining structures that are friendly to low-income and other low-usage ratepayers and increasing the benefits that low-income ratepayers receive from programs to promote local energy; and
- The compensation provided by local clean generation starts to become aligned more granularly with the underlying economics of the energy system, thus reducing any cross-subsidies and promoting efficient use of the system.

How do these reforms advance Acadia Center's long-term vision?

In the long term, advanced metering, more advanced energy management technology, and significant consumer education will make it possible to accurately charge and credit customers with distributed generation for the grid services they use and provide. Until these innovations are widespread, regulators should take incremental steps that advance this future. Acadia Center's five point plan is a move towards an improved cost causation basis for rates and net metering credits. These reforms also avoid traps like minimum bills that may address short-term issues, but do not reflect differences between customers and reflect an expansive view of fixed system costs

What needs to be done to achieve these reforms across the region?

No state in the region has all five of these reforms in place, but nearly every component has been implemented in at least one state. In many cases, these reforms do not require additional legislation and can be implemented by each state's public utility commission. However, issues related to net metering (the removal of any caps, authorization of community DG, and new net metering credit structures) typically do require legislation. Legislation can also encourage or require reforms to be undertaken by state agencies, even if they already have existing authority.

For more information:

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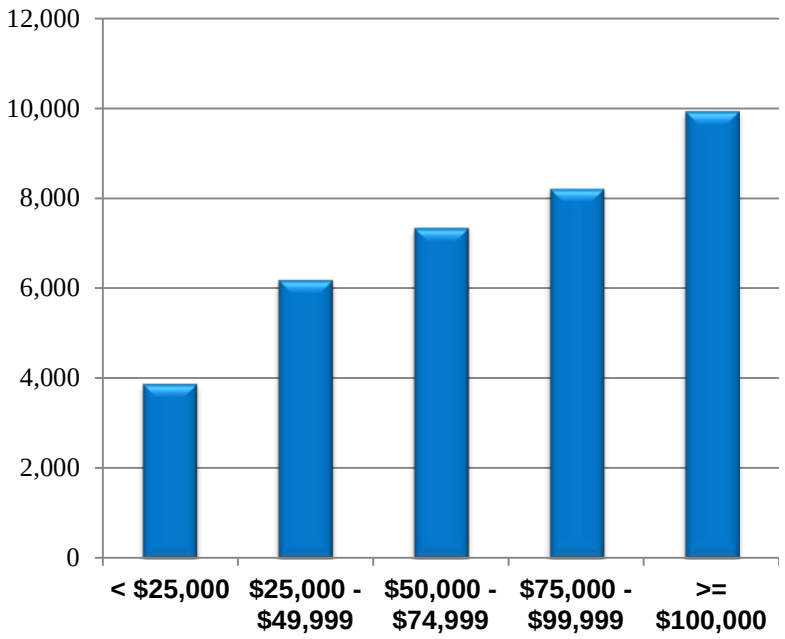
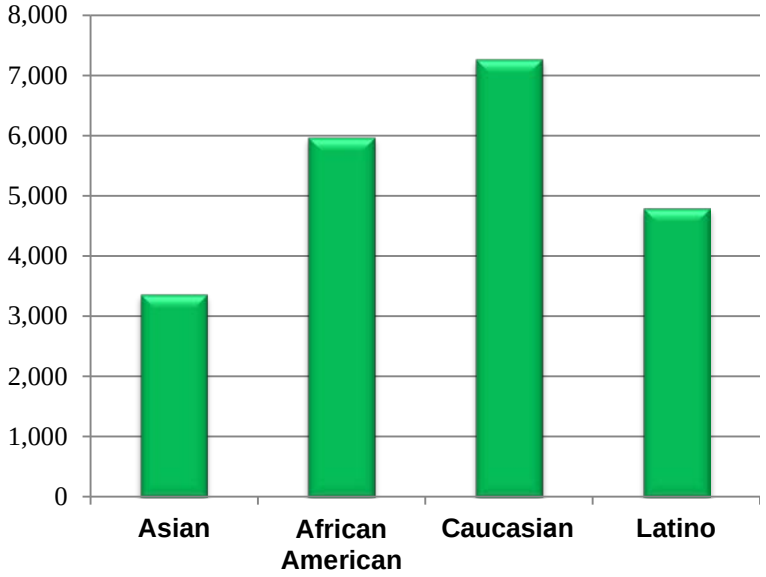
Utility Rate Design: How Mandatory Monthly Customer Fees Cause Disproportionate Harm

U.S. REGION: CT, ME, NH, RI, VT

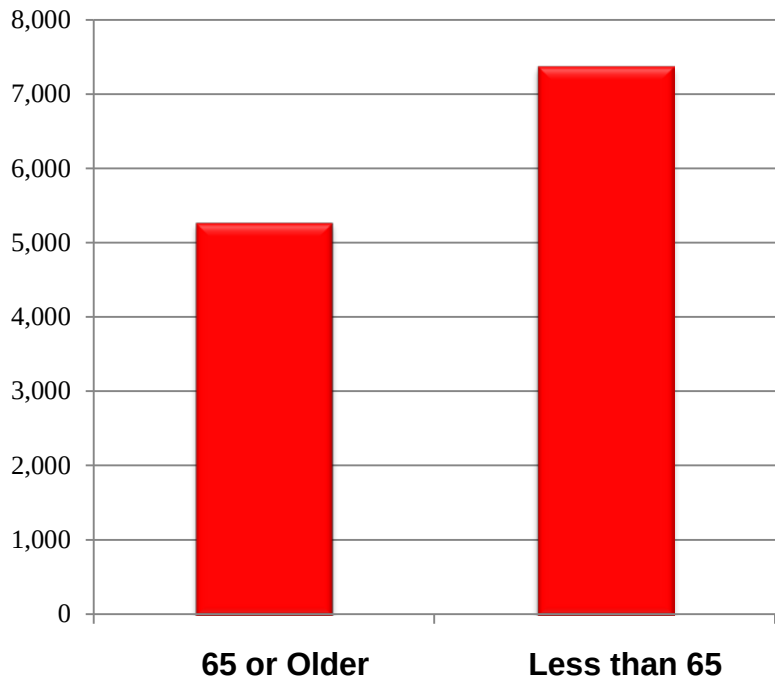
Median 2009 Residential Electricity Usage (KWH), by Income



Median 2009 Residential Electricity Usage (KWH), by Race/Ethnicity



Median 2009 Residential Electricity Usage (KWH), by Age



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

Source: U.S. Energy Information Administration's Residential Energy Consumption Survey, 2009 (most recent data available)

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