D.P.U. 15-120
Exhibit AG-PA-1
March 10, 2017
H.O. Tina Chin and Sarah Herbert

BEFORE THE

DEPARTMENT OF PUBLIC UTILITIES

COMMONWEALTH OF MASSACHUSETTS

In the matter of:

Massachusetts Electric Company and Nantucket Electric Company, both d/b/a National Grid

CASE NO. 15-120

DIRECT TESTIMONY

OF

PAUL ALVAREZ

ON BEHALF OF THE

OFFICE OF THE ATTORNEY GENERAL

Wired Group
PO Box 150963
Lakewood, CO 80215

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DIRECT TESTIMONY OF PAUL ALVAREZ

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Paul Alvarez. My business address is Wired Group, PO Box 150963, Lakewood, CO 80215.

Q. What is your occupation?

A. I am the President of the Wired Group, a consultancy specializing in the optimization of distribution utility businesses and operations as they relate to grid modernization (including smart meters), demand response, energy efficiency, and renewable generation.

Q. On whose behalf are you submitting testimony?

A. I am testifying on behalf of the Massachusetts Attorney General's Office (the "AGO").

Q. Please describe your work experience and educational background.

A. My career began in 1984 in a series of finance and marketing roles of progressive responsibility for large corporations, including Motorola's Communications Division (now Android/Google), Baxter Healthcare, Searle Pharmaceuticals (acquired by Pfizer), and Option Care (acquired by Walgreens).

My first job in the utility industry in 2001 was with Xcel Energy, one of the largest investor-owned utilities in the U.S. At Xcel Energy I served as product development manager, overseeing the development of new energy efficiency and demand response programs for residential, commercial, and industrial customers, as well as programs in support of voluntary renewable energy purchases and renewable portfolio standard compliance (including distributed solar incentive program design and net metering policy).

I left Xcel Energy to lead the utility practice for sustainability consulting firm MetaVu in 2008. At MetaVu I employed my DSM measurement and verification experience to lead two comprehensive, independent evaluations of smart grid deployment performance. To my knowledge these are two of the only three comprehensive, independent evaluations of smart grid deployment performance completed to date. (The third was conducted by the California Office of Ratepayer Advocacy.) The results of both were part of regulatory proceedings in the public domain and include an evaluation of the SmartGridCity™ deployment in Boulder, Colorado for

Xcel Energy in 2010,[1] and an evaluation of Duke Energy's Cincinnati-area deployment for the Ohio Public Utilities Commission in 2011.[2]

In 2012 I started the Wired Group to focus exclusively on distribution utility businesses and operations as they relate to grid modernization, demand response, energy efficiency, and renewable generation. Wired Group clients include regulators, consumer and environmental advocates, and industry associations. In addition, I serve as an adjunct professor at the University of Colorado's Global Energy Management Program, where I teach an elective graduate course on electric technologies, markets, and policy. I also serve as an instructor at Michigan State University's Institute for Public Utilities, where I educate new regulators and staff on grid modernization and distribution utility performance measurement.

Finally, I am the author of Smart Grid Hype & Reality: A Systems Approach to Maximizing Customer Return on Utility Investment, a book that helps laypersons understand smart grid capabilities, economics, optimum designs, and post-deployment performance optimization. I received an undergraduate degree from Indiana University's Kelley School of Business in 1983, and a master's degree in Management from the Kellogg School at Northwestern University in 1991. Both degrees featured concentrations in financial management and marketing management.

[1] Alvarez et al, MetaVu. "SmartGridCity™ Demonstration Project Evaluation Summary." Report submitted to the Colorado Public Utilities Commission in the testimony of Michael G. Lamb, Exhibit MGL-1, proceeding 11A-1001E. Report dated October 21, 2011; filed December 14, 2011.

[2] Alvarez et al, MetaVu. "Duke Energy Ohio Smart Grid Audit and Assessment." Report to the Staff of the Public Utilities Commission of Ohio in proceeding 10-2326-GE-RDR. June 30, 2011.

Q. Have you appeared before the Massachusetts Department of Public Utilities ("the Department") previously?

A. No.

Q. What experience do you have before other state utility regulatory commissions?

A. I have testified or developed evidence in cases before state utility regulatory commissions on smart meters, associated rate designs, grid modernization, and distribution utility performance measures in California, Colorado, Kansas, Kentucky, Maryland, and Ohio. Brief descriptions of these proceedings, and case numbers for each, are provided in the "Regulatory Appearances" section of my Curriculum Vitae, attached as Appendix A.

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

A. The purpose of my testimony is to present my recommendations regarding the Advanced Metering Functionality (AMF) components of the Company's Grid Modernization Plan (GMP). My testimony is divided into several parts. First, I describe my team's GMP review process and scope. Second, I outline the potential benefits of any AMF deployment—including, in this case, the Company's specific proposal—and the challenges that Massachusetts must address in order to maximize these benefits. In particular, I describe the important role that Critical Peak Price (CPP) and Peak-Time Rebate (PTR) rate features, and the associated peak demand response benefits they offer, play in achieving a favorable benefit-cost ratio for customers from AMF. Then, I outline the barriers that currently exist in Massachusetts to maximizing these benefits and recommend actions for removing the barriers. Finally, I outline aspects of the Company's GMP that reduce customer benefit-cost ratios for any approved GMP component and make recommendations to improve customer benefit-cost ratios. These recommendations apply to the Company's AMF-related proposals and to the grid-facing proposals evaluated by AGO witness Mr. Booth (to the extent any such proposals are approved by the Department).

Q. Before you present these arguments, can you please provide your overall impressions on the state of AMF deployments in the U.S. to date?

A. Yes. AMF has the potential to deliver economic customer benefits which exceed costs. To reach this potential, however, conditions must be suitable, utilities must be motivated, regulators must oversee, and customers must participate. I will describe the reasons for AMF deployment variability, and recommendations consistent with these perspectives, throughout this testimony. If the Department adopts my recommendations, I believe the probability that Massachusetts electric customers will secure benefits in excess of costs in future AMF deployments will increase significantly.

II. SCOPE AND PROCESS OF THE WIRED GROUP'S GMP REVIEW

Q. Please describe the scope of the Wired Group's review of the Company's GMP.

A. The Wired Group examined the customer-facing aspects of the Company's GMP. Wired Group personnel examined the Company's proposals for Advanced Metering Functionality (AMF); Customer Programs (time-varying rates, customer load management, and data access); and

Customer Education and Outreach. In these GMP component examinations my team reviewed, in the context of the team's collective prior grid modernization experience:

- The Company's cost estimates and associated rate impact estimates;
- The Company's benefit estimates;
- The Company's approaches to design, implementation, and ongoing management; and
- The Company's recommended technologies.

In addition, my team identified systemic issues external to utility control that might impact the Company's ability to deliver value from AMF deployments, including ISO-New England energy and capacity market structures and the status of retail choice in Massachusetts.

Finally, my team examined accounting, cost recovery, and ratemaking issues presented by the Company's GMP, including those issues which apply generally to any customer-facing or grid-facing components of the Company's GMP the Department might choose to approve.

III. PEAK DEMAND RESPONSE: THE LARGEST POTENTIAL AMF BENEFIT

Q. In your experience, what is the largest source of potential economic customer benefit from a typical AMF deployment?

A. A typical AMF deployment involves the replacement of traditional meters having limited data storage capabilities and no remote communication capabilities with "smart" meters having extensive capabilities in both areas. In my experience the largest source of potential, quantifiable economic benefit from a typical AMF deployment is the operating expense savings associated with the transition from manual meter reading (meter readers walking from house to house each month) to automated, remote meter reading. In Massachusetts, the EDCs have already automated meter reading and virtually eliminated all meter reading staff. Automated Meter Reading, or AMR, offers limited, remote communications capabilities to eliminate meter readers but no additional data storage capabilities of the type generally required for offering the advanced rate designs specified in D.P.U. 14-04-C. As a result, this large AMF-related benefit is not available.

Q. What are the implications for the Company's AMF business case?

A. The absence of the largest source of quantifiable economic benefit makes it more difficult for an AMF deployment to deliver customer benefits which exceed customer costs. To achieve a favorable benefit-cost ratio in such an AMF deployment, the Company would need to maximize the benefit potential of all other sources.

Q. In your experience, what is the second-largest source of potential economic customer benefit from a typical AMF deployment?

A. In my experience the second-largest source of potential economic customer benefit from a typical AMF deployment is peak demand response from customers. In any AMF deployment, and particularly in an AMF deployment without meter reading cost reduction benefits, peak demand response value must be maximized to secure a favorable AMF benefit-cost ratio for customers.

To maximize the economic benefit available from AMF-enabled peak demand response, many conditions, characteristics, and best practices must be exhibited.

Q. Please describe peak demand response and its value proposition for electric customers.

A. Peak demand response recognizes that a disproportionate amount of capital is spent to satisfy electric demand during a very limited number of hours during the year. In Massachusetts, these peak demand hours occur on the hottest summer days, when air conditioning loads are the greatest. Electric generation plants, the natural gas pipelines that deliver fuel to many of them, electric transmission lines, and electric distribution grids must all be built to meet maximum electric demand.

Peak demand response enlists customer efforts to reduce electric usage during periods of peak demand, thereby lowering peak demand and the amount of capital needed to satisfy it. Peak demand response programs, in which EDCs and/or third parties pay customers to reduce electric demand during peak demand periods, have been in place in various parts of the U.S. for decades.

In some states, EDCs and third parties fund peak demand response programs through participation in capacity markets organized by independent regional market facilitators such as ISO-New England. A peak demand response program operator can bid aggregated customer promises to reduce demand into organized capacity markets, receiving payments from market facilitators in proportion to the amount of electric demand that can be reduced during peak periods. Stiff economic penalties are levied on bidders who fail to deliver promised electric demand reductions when called upon.

Q. Can consumer electric rate design features support peak demand response?

A. Yes. Research indicates that Critical Peak Price (CPP) rate features are particularly effective at securing reductions from customers during peak periods. A CPP rate feature involves the use of a particularly high charge for electricity during a limited number of peak demand period events during a year, mimicking actual wholesale electric market price dynamics based on supply and demand. Customers are notified of these events one day in advance. AMF is required to record customer energy use during these high-priced periods. A survey of 43 CPP rate feature pilots indicates demand reductions of 5% to 50% are available from such features,[3] and a CPP rate feature study in Connecticut delivered a 16.1% reduction in peak period demand.[4] However, since CPP increases prices during peak demand periods, and increases energy management efforts required from customers, they are unlikely to choose CPP rate features voluntarily.

A peak demand response rate feature called Peak Time Rebate (PTR) pursues the same objective but in a manner that many customers find more palatable. Like CPP, customers are notified of peak demand events one day in advance. But contrary to the involuntary approach employed by

[3] Faruqui, Ahmad and Palmer, Jenny. *The Discovery of Price Responsiveness – A Survey of Experiments Involving Dynamic Pricing of Electricity.* EDI Quarterly, Volume 4, Number 1. April, 2012. Figure 3, Page 5.

[4] Faruqui et al. *Dynamic Pricing in a Moderate Climate: Evidence from Connecticut.* Study of Connecticut Light and Power's Plan-it Wise Energy Pilot. Figure 6, Page 27.

CPP (high prices at peak times), the PTR feature pays customers an incentive for demonstrated reductions in demand during peak period events. Past experience is used to establish individual baselines for each customer, to which electric usage during peak period events is compared to quantify customer reductions (if any) and incentive payments (if warranted). The PTR feature is therefore considered a voluntary program; a customer may reduce demand in response to a peak demand event if he or she chooses, but does not pay higher prices should he or she choose not to change energy usage behavior.

The PTR rate feature, because of its voluntary approach, is somewhat less effective than CPP at reducing usage during peak periods. However, research indicates that PTR still results in significant usage reductions while retaining the benefit of being a voluntary program. In a survey of 27 available PTR research studies, peak period demand reductions of 7 to 24% were observed,[5] and a study of the PTR rate feature in Connecticut delivered a 10.9% peak period demand reduction.[6] Therefore, I believe PTR can play an important role in securing benefits for customers from AMF deployments.

Q. Has the Department recognized the value of peak demand response rate features?

[5] Faruqui, Ahmad and Palmer, Jenny. *The Discovery of Price Responsiveness – A Survey of Experiments Involving Dynamic Pricing of Electricity.* EDI Quarterly, Volume 4, Number 1. April, 2012. Figure 3, Page 5.

[6] Faruqui et al. *Dynamic Pricing in a Moderate Climate: Evidence from Connecticut.* Study of Connecticut Light and Power's Plan-it Wise Energy Pilot. Figure 6, Page 27.

A. Yes. As noted earlier in my testimony, the Department established a policy to implement TOU rates with a CPP feature as the default for basic service customers in D.P.U. 14-04-C. In the industry, a "default" rate is generally known as the rate on which all customers in a class are automatically placed. Customers may take action to choose an alternative rate; these alternative rates are generally known as "opt-out" rates.[7] Also as noted earlier, D.P.U. 14-04-C established that the alternative rate available to basic service customers would be a rate with the PTR feature. Under Department policy, customers unhappy with the default CPP rate could opt-out to a rate with the PTR feature.

Q. In your experience, do peak demand response programs and rates with features like CPP and PTR offer significant customer benefit potential from AMF?

A. Yes. My experience evaluating AMF deployments indicates that rates with features like CPP and PTR offer the greatest potential, quantifiable economic benefit from an AMF deployment after meter reading cost reductions. In fact, my experience indicates that an AMF deployment is unlikely to deliver a favorable benefit-cost ratio for customers without the economic benefit potential of a significant peak demand response effort, including default application of rates with features like CPP and PTR and sophisticated and extensive customer education and outreach efforts.[8] As one

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[7] Lazar, J. and Gonzalez, W. (2015). *Smart Rate Design for a Smart Future.* Montpelier, VT: Regulatory Assistance Project. Available at: http://www.raponline.org/document/download/id/7680. Page 83.

[8] Alvarez, Paul. *Smart Grid Hype & Reality – A Systems Approach to Maximizing Customer Return on Utility Investment.* Wired Group Press, 2014. Chapter 9, "Smart Grid Benefit Cost Ratios." Smart Meter section, pages 141-146.

might expect, this is particularly true in instances, such as the Company's, in which meter reading benefits are not available.

The Company's benefit-cost analyses also confirm this perspective. In the Company's "Balanced" and "AMI-Focused" GMP scenarios, the benefit category "Time Varying Rates," which quantifies the benefits from the CPP and PTR rate features, is the single largest benefit. (Like Eversource and Unitil, the Company has already automated its meter reading function.) The Time Varying Rate benefit represents 49.71% of total AMF benefits in National Grid's Balanced GMP,[9] and 52.85% of total AMF benefits in National Grid's AMI-Focused GMP.[10] According to the Company's projections, neither of its two full AMF deployment scenarios would deliver a favorable benefit-cost ratio for customers without the CPP/PTR benefit. Of course, these are the Company's *projected* benefits; three primary determinants drive the size of CPP and PTR rate feature benefits that the Company, or any other EDC, would be able to deliver from an AMF deployment.

Q. What are the three primary determinants of CPP and PTR rate feature benefit size?

A. The three primary determinants of CPP and PTR rate feature benefit size are logical, and readily understood through a simple formulaic expression:

[9] D.P.U. 15-120, Attachment 10A (Balanced BCA). Tab "3. Benefits." 49.71% = Time Varying Rate Benefits divided by (Total Benefits less DA-related benefits).

[10] D.P.U. 15-120, Attachment 10B (AMI-focused BCA). Tab "3. Benefits." 52.85% = Time Varying Rate Benefits divided by (Total Benefits less DA-related benefits).

$$\begin{matrix}\text{CPP/PTR}\\ \text{Benefit}\\ \text{Size}\end{matrix} = \begin{matrix}\text{Number of}\\ \text{Participating}\\ \text{Customers}\end{matrix} \times \begin{matrix}\text{Average}\\ \text{Size of}\\ \text{Demand}\\ \text{Response}\end{matrix} \times \begin{matrix}\text{Value per}\\ \text{Unit of}\\ \text{Demand}\\ \text{Reduced}\end{matrix}$$

These three primary determinants are featured in the CPP/PTR benefit calculations in the benefit-cost analyses of all AMF deployment scenarios proposed or evaluated by the EDCs in their GMPs. As the primary determinants grow in size, benefits grow; as the primary determinants shrink, benefits shrink. The key to securing a favorable benefit-cost ratio for customers is to maximize the benefit for a given level of cost (the cost of AMF deployment). Multiple secondary conditions and characteristics, which I discuss below, influence each of the primary determinants of CPP/PTR benefit size. Unfortunately, significant challenges to optimum conditions and characteristics for all three primary determinants exist in Massachusetts today, and I'll discuss these in the next section of my testimony.

Q. So, is it your view that the Company's projections for CPP/PTR benefits are not achievable under current conditions in Massachusetts?

A. Yes, that's correct. I will discuss this in the next section of my testimony.

Q. Can you explain why other AMF deployment benefits are not sufficient to make up for the lack of CPP/PTR benefits?

A. There are many other potential economic, quantifiable benefits available from AMF, including improved revenue assurance (from reductions in theft and meter error), reduced metering services costs (from remote service disconnect and reconnect capabilities), and deferred capital spending (as replacements for old, defective meters would likely be avoided for a decade or more with the installation of all new AMF meters). In my experience, however, and consistent with the Company's benefit-cost analyses, the combined benefits from these sources are not large enough to make up for the significant reduction that needs to be made to the Company's projected CPP/PTR rate feature benefit as a result of current conditions in Massachusetts. Again, I will support the rationale for this expectation in the next section of my testimony.

Q. What about the non-economic and/or non-quantifiable benefits? Are non-economic and non-quantifiable benefits available to customers from AMF?

A The Company cites several types of non-economic and/or non-quantifiable benefits related to AMF in its GMP, including reductions in GHG emissions from AMF-related conservation benefits, and improvements in customer satisfaction. I agree these benefits are available from a full AMF deployment. In this case, I do not believe that these benefits are significant enough to overcome the concerns I described above regarding the economic cost/benefit analysis.

IV. CHALLENGES TO MAXIMIZING CPP/PTR BENEFITS IN MASSACHUSETTS AND ASSOCIATED RECOMMENDATIONS

Q. You mention that one of the most significant variables driving the CPP/PTR rate feature benefit is the number of customers participating in rates with such features. Please describe the challenges to maximizing customer participation in rates with CPP/PTR features in Massachusetts today.

A. One challenge to maximizing the number of customers participating in rates with CPP/PTR features in Massachusetts today is retail choice. The number of electric customers in Massachusetts who secure electric supply outside of distribution utilities' basic service offers has never been higher. In fact, since the Department issued its order in 12-76-B requiring GMPs from Massachusetts EDCs in June of 2014, the percentage of residential customers securing electric supply outside of basic service has increased to 37.2%,[11] driven largely by municipal aggregation.[12] As a result, the Department's policy of default application of CPP or PTR rate features for basic service applies to fewer and fewer customers as time passes. Installing AMF for 100% of customers (as would be required for default application of CPP or PTR rate features), but assuring that only 62.8% of them *at most* can participate in CPP/PTR rate features, is certain to

[11] Massachusetts Department of Energy Resources. *Competitive Supply Migration Report*. October, 2016. Accessed via the Internet at http://www.mass.gov/eea/grants-and-tech-assistance/guidance-technical-assistance/agencies-and-divisions/doer/electric-customer-migration-data.html on Monday, January 30, 2017.

[12] Indeed, the number of customers on competitive supply is likely to increase significantly in the near future. As of February 23, 2017, there are forty-three towns with municipal aggregation plans that either have been approved by the Department since October 1, 2016 or are currently pending approval. Twelve towns have plans that were approved; thirty-one towns are pending approval. See DPU Website, http://www.mass.gov/eea/grants-and-tech-assistance/guidance-technical-assistance/agencies-and-divisions/dpu/.

reduce the AMF benefit-cost ratio relative to a scenario in which 100% of customers could participate in rates with CPP/PTR features.

Furthermore, a structural change to basic service customers' default service rate may lead a certain number of customers to investigate and choose a competitive supplier with a traditional flat rate per kWh, further reducing the number of customers participating in CPP or PTR rates through an EDC's basic service offer.

Q. Do the Company's benefit projections reflect this challenge?

A. No. Rather, the Company's projections assume that between 66% and 71% of its distribution customers will be participating in rates with demand response features, though data shows that only about 58.8% of the Company's distribution customers currently receive basic service from the Company.[13]

Q. Is there anything that can be done about this challenge?

A. Yes, I believe there is. One example for maximizing customer participation in rates with peak demand response features in a retail choice state can be found in Maryland. In Maryland, a state with both retail choice and full AMF deployment, EDCs calculate and pay Peak Time Rebates to

[13] Exh. AG-3-31, Att. AG-3-31(b), PUBLIC NGrid BCA Tool AMI-Focused scenario_PDF_Redacted 030117.pdf. Tab "13.DSM," line 233, "Penetration of CPP Rates (Residential)"; Massachusetts Department of Energy Resources. *Competitive Supply Migration Report*. October, 2016. Accessed via the Internet at http://www.mass.gov/eea/grants-and-tech-assistance/guidance-technical-assistance/agencies-and-divisions/doer/electric-customer-migration-data.html on Monday, January 30, 2017.

all distribution customers *regardless of the rate a customer is on or the electric supplier a customer chooses*. This requirement increases customer participation, thereby improving the AMF benefit-cost ratio for all customers. In addition, customer education and outreach spending can be focused on behavior change and instruction rather than recruiting (more on that below). The EDCs in Maryland pay for program administration, customer education and outreach, and rebates paid to customers, by bidding capacity they expect to secure from the PTR rate feature into the PJM capacity market as I described earlier.

Q. Do you offer a related recommendation?

A. Yes. I recommend the Department establish a proceeding to consider how to maximize the CPP/PTR-related benefits of AMF deployments given the issue of falling basic service participation, to include the option of expanding PTR to all customers regardless of energy supplier. This proceeding could also be designed to address other specifics of a CPP/PTR rate which have yet to be satisfactorily determined, as described later in this section of my testimony.

Q. You mention that another of the most significant variables driving the CPP/PTR rate feature benefit is the economic value which can be captured from CPP/PTR-related demand reductions. Please describe the challenge to maximizing the economic value of such reductions in Massachusetts today.

A. Unfortunately, there is a discrepancy between the timing of maximum CPP and PTR rate features' demand response potential and the opportunity for utilities or third parties to monetize aggregated demand reductions in ISO-New England's capacity market. While CPP/PTR peak demand reduction potential peaks in the summer in Massachusetts (due to air conditioning loads), ISO-New England defines capacity as a *year-round* product. That is, ISO-New England requires its capacity suppliers to make capacity available whenever the system requires it throughout a given capacity performance period. In ISO-New England, the capacity performance period runs from 12:00:00 am on June 1 through 11:59:59 pm on May 31 of the following year.

As a result of this definition, an EDC or third party with CPP/PTR-related summer peak demand reductions to offer to the ISO-New England capacity market would need to bid in with resources that could reduce the same load in the winter. Because the region is a summer peaking system it would be difficult to find equivalent winter reductions. Failure to make the promised reductions would result in large financial penalties for lack of performance.[14]

Q. Do the Company's benefit projections reflect this challenge?

A. No. The Company's CPP/PTR benefit calculations are quite aggressive, and not reflective of current ISO-New England forward capacity market designs or conditions. The Company's benefit projections for CPP/PTR benefits appear to include both summer-sized reductions in peak period demand response and very high market prices for capacity reductions. Neither is likely possible given the current constructs of the ISO-New England capacity markets as described above.

[14] ISO-NE, Transmission, Markets and Services Tariff, III.13, III.13 Forward Capacity Market.

The Company assumed reductions equal to 8.4% of participating customer demand.[15] I do not believe this level of demand response is possible from residential customers in seasons other than summer, with its high air conditioning loads. Yet, for the reasons described above, I do not believe it is feasible for the Company to bid summer demand response into ISO-New England's current year-round capacity market without bidding in equivalent winter demand reduction.

Additionally, the Company's assumed capacity valuations are very high relative to current market clearing prices. In the most recent ISO-New England year-round forward capacity market auction, the clearing price for capacity offers from June 1, 2020 to May 31, 2021, was $63.56 per kW-year.[16] However, the Company's assumptions for avoided capacity value ranged from $200 to $300 per kW-year.[17]

Q. Is there anything that can be done about this challenge?

A. Yes, I believe there is. One potential solution is to define capacity markets in accordance with the seasons. Summer capacity commitments would be based on managed summertime loads and be called upon by ISO-New England only in summer months, while winter capacity commitments would be based on wintertime loads and be called upon by ISO-New England only in winter months. As an example, New York ISO offers a summer capacity product and a winter capacity

[15] Exh. AG-3-31, Att. AG-3-31(b) PUBLIC NGrid BCA Tool AMI-Focused scenario_PDF_Redacted 030117.pdf". Tab "13.DSM," line 420, "Percent Demand Reduction from CPP Rate (Residential) (%).

[16] Forward Capacity Market (FCA 11) Results Report. ISO-New England. Accessed via the Internet at https://www.iso-ne.com/isoexpress/web/reports/auctions/-/tree/fcm-auction-results

[17] Exh. AG-3-31, Att. AG-3-31(b), PUBLIC NGrid BCA Tool AMI-Focused scenario_PDF_Redacted 030117.pdf. Tab "52.RATES,LOAD,SALES," line 15, "Avoided Cost of Demand ($/kW).

product. PJM and MISO are currently exploring the peak demand response opportunity available from seasonal capacity markets, and the FERC has a related docket underway (EL17-32).

Q. Do you offer a related recommendation?

A. Yes. I believe interested stakeholders should work with ISO-New England to establish a proceeding to resolve capacity market issues which result in a failure to reflect the true economic value of summer peak demand reductions available from the residential customer class (targeted for AMF deployment).

Q. Finally, you cite the size of behavior change demonstrated by customers participating in CPP/PTR rates as one of the most significant variables driving CPP/PTR benefits. Please describe the challenges associated with maximizing this behavior change.

A. Common sense, as well as research into CPP/PTR rate feature response, indicates that the easier it is for customers to reduce demand during a peak period event, the larger the associated demand reductions will be. The use of enabling technologies and services, from smart thermostats and direct load control to in-home energy displays and curtailment service providers, are likely to increase the size of demand response demonstrated by customers. A study of CPP and PTR rates in Connecticut, for example, estimated peak demand reductions 44.7% and 66.3% larger, respectively, for residential customers utilizing enabling technologies (smart thermostats and direct load control) compared to residential customers without such technologies. With enabling technologies, CPP and PTR rate features in Connecticut yielded peak period demand reductions of 23.3% and 17.8%, respectively, compared to 16.1% and 10.9%, respectively, without enablers.[18]

I believe curtailment services provided to CPP and PTR rate participants by either EDCs or third parties also have the potential to maximize customer response during peak periods by reducing the effort required from customers during a peak event. However, the concept of regulated or competitive curtailment service offerings for the residential market has not been defined sufficiently in Massachusetts (or elsewhere) to make definitive conclusions about quantitative benefits.

Q. And what other barriers exist to allowing curtailment services to maximize customer response to peak period events, and therefore benefits available from CPP/PTR rates?

A. Data access policies which might be of value in helping curtailment service providers reduce demand during peak period events also have not been adequately defined. For example, the Green Button "Connect My Data" standard[19] was developed to allow a customer to specify the service providers to which the customer wishes to authorize ongoing access to his or her energy usage data without manual intervention. The standard also addresses the protocols by which authorized service providers can access their customers' energy use data in a secure, automated manner from

[18] Faruqui et al. "Dynamic Pricing in a Moderate Climate: The Evidence from Connecticut." Electronic copy available at: http://ssrn.com/abstract=2028178. Figure 6, page 27.

[19] Green Button Connect My Data standard. Available from the Green Button Alliance. www.greenbuttonalliance.org.

EDCs; this is important for high-volume execution. The Connect My Data standard lays the foundation for third-party participation in energy management.

Additionally, it is conceivable that curtailment service providers might need energy usage data for tens of thousands of their customers simultaneously, in near-real time, during a peak period event. While I cannot state unequivocally that such capabilities will be needed in the future, or that they will deliver benefits in excess of costs, neither am I certain that such capabilities will *not* be necessary or valuable in the future.

Q. What's wrong with deploying AMF without clarity on data access policies?

A. In general, of all the outstanding issues needing resolution I've cited, the consequences associated with the lack of a data access policy may be particularly high. The AMF data communications networks most utilities are implementing, at a cost of tens of millions of dollars per metropolitan area, do not provide for simultaneous communication of energy usage data for tens or hundreds of thousands of customers in near-real time. Unless specific data access requirements, which many refer to as "use cases," are defined in advance of deployment, there is a risk that installed AMF communications networks will promptly be rendered obsolete at a high cost to ratepayers.

Q. What do you suggest regarding this challenge?

A. In D.P.U. 12-76-A, the Department indicated it would establish a separate proceeding "to explore how the Department should ensure: (1) protection of customer data privacy; (2) access to data by customers and authorized third parties; (3) timing and availability of data; and (4) uses of aggregated interval data."[20] Going forward with this data access proceeding could allow the Department to address these data access issues. I also suggest expanding the scope of the intended proceeding to address whether curtailment services should remain the domain of EDCs, or be opened to competitive third-party energy management service providers. I recommend an examination into the likely benefits, costs, and risks associated with both options be part of an expanded proceeding, leading to an informed decision on this issue.

Q. Are there any other challenges to maximizing the benefits of CPP/PTR rate features in Massachusetts today?

A. Yes. I believe a Department proceeding is required to further specify CPP/PTR rate designs and offer protocols. While D.P.U. 14-04-C establishes the policy that a CPP rate should be the default approach for basic service customers, and that a PTR rate design feature should be part of any basic service rate option, multiple details still need to be resolved.

For example, the Department, with coordination with ISO-New England, would need to determine:

- Which organization is responsible for calling peak demand event days? ISO-New England? The Department? Individual EDCs or curtailment service providers?
- How many peak demand event days can be called in a year? 10? 12? 20? Can they be called on consecutive days? If so, for how many consecutive days? Are event day limits different for summer vs. winter?

[20] Modernization of the Electric Grid, D.P.U. 12-76-A, at 37 (2013).

- How is the peak demand period defined for summer event days? 2-8pm? 4-8 pm? Is this the same period as a prospective seasonal capacity product from ISO-New England?
- How is the peak demand period defined for winter event days? 6-9 am? 6-9 pm? Both? Is this the same period as a prospective seasonal capacity product from ISO-New England?
- What is the kWh price for peak demand hours under CPP? Is this the same as the kWh incentive paid under PTR? Are there differences between winter and summer?
- Is the EDC responsible for calculating and paying peak-time rebates to municipal aggregation and competitive supply customers?
- What are the mechanics of the PTR behavior change calculation? How are baselines established? Are rewards to be paid per event? per month? per season? or annually?
- Is new research available, or have circumstances changed since the Department issued its order, that would cause the Department to rethink elements of its Order in 14-04-C?
- Should EDCs be required to make PTR available to all distribution customers regardless of the source of supply, be it EDC basic service, municipal aggregation, or competitive supplier?

All of these specifics impact the variables I discussed above -- customer participation, the economic value per unit of demand reduction that can be captured, and the size of customer behavior change – and therefore the value of an AMF deployment and the associated benefit-cost analyses.

Q. Do you offer a related recommendation?

A. Yes. I recommend the Department establish a proceeding to consider how to implement CPP and PTR rate features in Massachusetts.

V. OVERALL REASONABLENESS OF THE COMPANY'S GMP AND ASSOCIATED RECOMMENDATIONS

Q. Please describe your evaluation of the overall reasonableness of the Company's GMP.

A. My team's evaluation of the overall reasonableness of the Company's GMP examined those parts of the Company's GMP which apply equally to either customer-facing or grid-facing GMP components. Questions which came up during the overall reasonableness evaluation included:

- Who bears the risk of any cost overruns for approved GMP components?
- Might the timing of rate cases impact the return of GMP-related economic benefits to customers?
- Who loses in the event benefits projected by the Company for approved GMP components are not achieved?
- Might the deployment of approved GMP components force early retirement of assets in service? If so, how will the recovery of associated book value write-downs impact rates?
- Are the Company's GMP cost recovery proposals consistent with historical ratemaking and cost-recovery practices and precedents? If not, has such departure been authorized by the Department in 12-76-B or other orders?

- How can the value of Customer Education and Outreach spending be maximized?

Q. Please describe your concerns regarding cost overruns.

A. In my experience, grid modernization cost overruns are much more likely than under-budget performance. In the only two independent evaluations of smart meter deployment costs of which I am aware, including one evaluation I led,[21] and one led by the California Office of Ratepayer Advocacy,[22] both demonstrated significantly higher capital and operating costs than anticipated. Generally, there are three possible responses to a utility's GMP cost overruns:

- Capabilities or deployment scope are curtailed (generally resulting in lower benefits for customers);
- Customer rates are increased by an amount greater than originally approved; or
- Costs are disallowed.

Regulator disallowance is rare in cases of grid modernization. I know of only one case in which recovery of grid modernization cost overruns from customers was denied.[23] It is difficult to make a showing under a prudency review standard, like that in Massachusetts, that cost overruns associated with grid modernization investments were imprudent or unreasonable based on what the Company "knew or should have known at that time . . . in light of existing circumstances."[24]

[21] Alvarez et al. *SmartGridCity™ Demonstration Project Evaluation Summary*. Colorado PUC11A-1001E. Exhibit MGL-1. Filed December 14, 2011.

[22] Hieta, Kao, and Roberts. *Case Study of Smart Meter System Deployment*. California Office of Ratepayer Advocacy. March, 2012.

[23] Colorado Public Utilities Commission. Decision R13-0096 in Proceeding 11A-1001E.

[24] D.P.U. 12-76-B, at 24.

In my experience cost overruns are much more likely to result in customer benefit reductions, unanticipated rate increases, or both, rather than disallowances.

In connection with excessive cost overruns, the Department expects an EDC to apprise the Department before making commitments to proceed with investments likely to "materially exceed" GMP estimates, and to demonstrate that any cost increases in excess of estimates were outside of its control.[25] This type of prudency review, as outlined by D.P.U. 12-76-B, will not be sufficient to adequately protect ratepayers in each instance of cost overruns, especially for those not deemed "excessive." As a result, I think some sort of cost risk-sharing mechanism is appropriate for any customer-facing or grid-facing GMP investment the Department might approve.

Q. Do you offer any related recommendation?

A. Yes. I believe it would be reasonable for the Department to require, as a condition for any proposed GMP component the Department elects to approve, that costs in excess of amounts projected by the Company in its benefit-cost analyses be split 50:50 between customers and shareholders.

Q. Has this recommendation been implemented in any other grid modernization projects?

A. I am not aware of any other grid modernization projects in which regulators have implemented such a condition, but it is reasonable for the Department to do so here.

[25] D.P.U. 12-76-B, at 24.

Q. Please describe your concerns regarding projected versus actual benefits.

A. I have found benefit projections to be notoriously unreliable, and actual post-deployment performance to be subject to an extremely high level of variability relative to projections. In available research, actual benefits have been found to be much less than projected benefits.[26] In my research, several conditions seem to contribute to these deficiencies:

- Low participation in opt-in rates, as described above;
- Economic incentives established for EDCs through routine ratemaking practice, such as EDC incentives to "time" rate cases (EDC control of the timing of GMP-related benefits, as well as EDC control of the timing of rate cases, can be "gamed" to secure certain GMP-related benefits for shareholders while denying them to ratepayers);
- Organizational and operational challenges, including a lack of motivation, to the maximization of GMP-related investment benefits; and
- Insufficient post-deployment oversight.

Q. Do you offer any related recommendations?

A. Yes. I believe performance measurement programs of a more rigorous nature than those proposed by the other EDCs and the Company should be employed to help ensure benefit projections are

[26] Alvarez et al. *SmartGridCity™ Demonstration Project Evaluation Summary*. Colorado PUC 11A-1001E. Exhibit MGL-1. Filed December 14, 2011; Alvarez et al. *Duke Energy Ohio Smart Grid Audit and Assessment.* Ohio PUC 10-2326. Filed June 30, 2011; Hieta, Kao, and Roberts. *Case Study of Smart Meter System Deployment*. California Office of Ratepayer Advocacy. March, 2012.

realized. I describe the characteristics of a rigorous performance measurement program, including outcomes-based performance metrics, pre-deployment baseline measures, associated targets, interim and ultimate timeframes, and reporting requirements, later in this section of my testimony.

Q. Please describe your concerns regarding rate case timing and the return of GMP-related economic benefits to customers.

A. Investor-owned utilities are highly motivated to recover the costs of grid modernization. Here, the Department has authorized the EDCs to recover costs on an annual basis through a capital expenditure tracker.[27] While this ensures that the EDCs recover capital costs and associated profits, there is no similar effort to ensure that certain economic benefits delivered by these investments are reflected in customer rates. In fact, until an EDC files a future rate case, operating expense reduction benefits will be delivered to shareholders rather than customers. Customers end up paying the cost of grid modernization (including associated EDC profits) with no access to these economic benefits for as long as this future rate case is delayed.

Q. Please explain your concern about timely customer realization of benefits further.

A. Though I will use the example of a smart meters to illustrate, the rate case timing concept applies to all grid modernization investments, including grid-facing investments. The concept is based on the fact that utilities control when the operating expense reductions from a GMP investment are delivered. When it comes to operating expense reductions, a utility can simply avoid laying off

[27] D.P.U. 12-76-B, at 22.

employees or cancelling contract work until after a test year. By delaying such actions, the old, "pre-deployment" circumstances and costs are included in test year accounting records and reflected in customer rates determined through the use of that test year's data. However, once rates are set, and recovery of these costs from ratepayers is assured, the utility can simply execute the cost-reduction and revenue assurance plans *after* the test year. In this manner shareholders, not customers, reap the operating expense reduction benefits of the GMP investments (and associated profits) for which customers are paying through the tracker.

Thus, the Company proposes to recover all of its costs through the annual tracker, but ratepayers will not see the benefit of any savings until after the Company's next test year. Because Massachusetts allows five years between rate cases, any savings achieved from GMP-related investments only benefits shareholders for a number of years. Therefore, I recommend that the Department consider some type of mechanism designed to return, on a timelier basis, the economic benefits of any customer-facing or grid-facing GMP investments the Department might approve.

Q. Do you offer any related recommendation?

A. Yes. I believe it would be reasonable for the Department to specify, as a condition for any proposed GMP component the Department elects to approve, a mechanism to reflect operating expense reduction, as projected by the Company in benefit-cost analyses for such components, on customers' bills rather than waiting for a rate case. In Oklahoma[28] and Ohio,[29] this was achieved through tracker revenue requirement reductions based on benefit size and timing projected by EDCs in their benefit-cost projections.

Q. Can you explain these mechanisms in greater detail?

A. Yes. Assume for purposes of illustration an EDC projects the following operating expense reductions from faster location of outages (via reduced crew time, overtime, and use of contractors, for example):

GMP Year	Projected Op Ex Reduction
6	$300,000
7	325,000
8	350,000
9	375,000
10	400,000

In this illustration shareholders, not customers, would reap $1.75 million in economic benefits before a rate case is held using GMP year 10 as a test year. Rather than wait for a rate case, regulators in Oklahoma and Ohio specified that the GMP-related revenue requirements (capital trackers) be reduced by the amount of the benefits projected by the EDCs in their benefit-cost analyses:

[28] Corporation Commission of Oklahoma. Order 576595 in Cause PUD 201000029. Finding of Fact 12. July 1,2010. Page 18.

[29] Public Utilities Commission of Ohio. Stipulation and Recommendation in Case 10-2326-GE-RDR. Section II. February 24, 2012. Pages 5-10.

Tracker Year	Adjustment in Tracker Revenue Requirement
6	-$300,000
7	-325,000
8	-350,000
9	-375,000
10	-400,000

This approach delivers several benefits to customers. First, it delivers economic benefits to customers – benefits which they are paying to obtain through the GMP tracker -- without having to wait for a rate case to recognize benefits in rates. Second, it holds an EDC accountable for delivering the size of benefits it projects in its benefit cost-analysis. Third, it holds an EDC accountable for the speed at which benefits are to be delivered. And finally, it provides an economic incentive for the EDC to secure economic benefits.

Q. Please explain your concern about the organizational and operational challenges, including a lack of motivation, to maximizing the benefits of GMP-related investments and capabilities.

A. In my experience, EDC organizational and operational challenges can prevent the optimization of benefits. To implement a GMP, an EDC must change its operating policies and processes, train employees, and enforce policy and process changes. In some cases, an EDC must make organizational changes. EDCs must be innovative, identifying opportunities to employ newly-available data in ways that improve service or reduce costs. If the EDC is not motivated to maximize benefits, and there is no oversight to ensure projected benefits are secured, it is entirely possible that organizational and operational challenges can prevent projected benefits from being maximized or secured.

Thus, "EDC motivation" is another benefit associated with the implementation of the rate-case timing mechanism described above. If the EDC secures benefits greater than projected, or secures them earlier than projected, shareholders benefit; if the EDC fails to secure the size of benefits projected, or fails to secure them in the timeframes projected, shareholders lose. I believe the rate-case timing mechanism therefore provides the necessary motivation for EDCs to overcome the organizational and operational challenges associated with securing GMP-related benefits for operating expense reductions. In addition, I believe post-deployment benefit measurement is another tool regulators should use to ensure GMP-related benefit projections are achieved.

Q. Why do you believe post-deployment benefit measurement should be used in addition to your recommended rate-case timing mechanism?

A. The recommended rate-case timing mechanism is intended to secure operating expense benefits for customers in between rate cases. Other GMP-related benefits, from reliability improvements and conservation voltage reduction to customer demand response and energy efficiency, cannot readily be addressed through accounting mechanisms. For these types of GMP-related benefits, post-deployment measurements are required to gauge success relative to EDC projections.

Q. In your experience, what are the characteristics of a sound, post-deployment benefit measurement program?

A. I believe a sound, post-deployment benefit measurement program exhibits the following characteristics:

- Clearly-defined metrics (such as “average voltage per circuit, per year” or “MW reduction exhibited during a peak period event” or “percent of customers who can describe the goal of a peak period event without prompting” or the various reliability metrics defined by IEEE standard 1366: SAIDI, SAIFI, and CAIDI per circuit);
- Pre-deployment baseline measures as appropriate;
- Outcomes-based performance targets, with timeframes, consistent with the EDC’s benefit projections; and
- Clearly-defined, periodic, interim and annual reporting requirements.

Performance targets should be *outcomes-based*, not *process-based*. For example, several performance measures recommended by the EDCs for use statewide consist of process measures. On their own, these are inadequate for measuring post-deployment performance. Consider the statewide EDC-recommended measurement “Reduce the Impact of Outages.” The metric “Customers Benefiting from Grid Modernization Devices” is a process measure related to the extent of an IOU’s grid automation deployment.[30] It does not measure how well an IOU uses grid automation to improve reliability measures like SAIDI. Process-based targets measure Company activities, whereas outcomes-based targets measure Company performance.

Q. Do you offer any related recommendations?

[30] Exh. NATIONAL GRID-GMP, p. 170. Table 24 – Statewide Performance Metrics.

A. Yes. I recommend that a post-deployment performance measurement program, exhibiting the characteristics described above, be established for every one of the Company's GMP-related capabilities which the Department approves.

Q. Please explain your concern about the write-off of in-service assets' book values that might be prompted by grid modernization.

A. Grid modernization can result in the premature retirement of assets, as well as associated cost increases for customers as these in-service assets are written off. When one in-service asset with a book value is retired to make way for a modern grid version, customers pay for two assets at once. Recovery of costs for the first asset are still reflected in rates, while the recovery of the second asset's cost is added to rates (or, in Massachusetts' case, to the capital expenditure tracker). This "stranded asset" issue is common for utilities generally and for grid modernization specifically.

A related concern is the starting point and timeframe over which the stranded investment costs are recovered. Later starting points and longer timeframes mitigate the bill shock to ratepayers.

Q. Please describe the Company's proposal for stranded investment cost recovery.

A. The Company proposes to establish a regulatory asset for the undepreciated value of the assets being prematurely retired, and to initially amortize that asset in an annual amount equal to the then current level of rate recovery of those assets (a depreciation allowance) included in either base rates or the Company's CapEx tracker mechanism. At the time of the Company's next base rate case, the remaining value of such regulatory asset would be amortized over a period of three years, and an associated profit earned using the Company's weighted average cost of capital, adjusted to reflect the income tax rates in effect for the applicable year throughout this period.[31]

Q. Do you offer any related recommendation?

A. Yes. A significant body of Department precedent exists on this issue. This precedent, as reiterated in D.P.U. 12-76-C, allows the Company to recover the remaining balance of its stranded asset costs, but without a rate of return (profit).[32] The Department's precedent balances the interests of the Company with the interests of customers, allowing the Company to recover prudently-incurred costs, but relieving customers of the requirement to pay profits on assets that are no longer used and useful. I recommend this Department precedent be followed for stranded costs that might result from any proposed GMP capabilities the Department approves.

Regarding the issue of bill shock, I think it would be equitable that the start of stranded asset cost recovery should match the start of the benefit period of the modern grid assets. In addition, as the capital tracker, or "STIP,"[33] is for a five-year period, I suggest that a five-year amortization period would be more reasonable than the three-year period proposed by the Company. Finally, rather than leave these decisions for some future rate case, I suggest they be determined now, enabling component-specific approval decisions to be made with more complete information.

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[31] Exh. PTZ-1 (updated), pp. 20-21.

[32] Modernization of the Electric Grid, D.P.U. 12-76-C, at 28 (2014).

[33] The capital tracker is also referred to as the "STIP" for "Short Term Investment Plan." D.P.U. 12-76-B, at 3-5.

Q. Are there other proposals by the Company which contravene Department practices and precedents related to ratemaking and cost recovery in the Company's GMP that reduce its overall reasonableness and/or benefit-cost ratio?

A. Yes. I am troubled by two additional proposals. One is that the Company proposes to recover O&M costs in the tracker mechanism approved by the Department for GMP-related capital costs. Another is that the Company proposes to recover some GMP-related costs in a fixed customer charge per month rather than in a volumetric customer charge based on usage (i.e., cents per kWh).

The Department's Order in 12-76-B allows companies to file for cost recovery of the incremental capital investment in their STIP that are made for (1) AMF or (2) other incremental grid modernization capital investments, but the latter only as part of a STIP that also addresses AMF. The Department did not allow recovery of O&M costs associated with the investments or ongoing O&M costs pertaining to the new assets once they are in service. However, that is precisely what the Company proposes in its GMP, for both the STIP Provision[34] and RD&D Provision.[35] Company witness Zschokke cites two concerns regarding the prohibition against recovering O&M costs in a tracker mechanism. First, that the Company would need to fund those O&M costs out of pocket until the next rate case. Second, that the Department is sending a signal to the Company regarding the types of spending the Department favors (capital over O&M).

[34] Exh. NATIONAL GRID-GMP, p. 209.

[35] Ibid. Page 210.

I do not believe either of these Company concerns holds merit. First, the Department has already considered and decided the issue. Second, it is standard cost of service ratemaking for a distribution company to fund costs between rate cases. Third, the preference for capital spending over O&M spending is not a new issue; it has been inherent in the application of the cost-based ratemaking model since the 1930s.

Q. Do you have any recommendations related to the recovery of GMP-related O&M costs in the capital tracker approved by the Department?

A. Yes. I recommend the Department order the Company to exclude GMP-related O&M costs from the capital tracker approved by the Department, leaving these costs to be recovered in a general rate case.

Q. Please discuss your concern that the Company proposes to recover some GMP-related costs in a fixed customer charge per month rather than in a volumetric customer charge based on usage (i.e., cents per kWh).

A. The Company proposes to recover customer-facing costs through a monthly customer charge, and grid-facing costs through a volumetric charge per kilowatt-hour ("kWh").[36] If the Department approves any of the customer-facing components of the Company's GMP, the Department should not change its policy to allow the recovery of the costs through a monthly customer charge, particularly outside of a rate case.

[36] Exh. CRP-1, p. 7.

The Company's proposal to recover costs through a fixed monthly customer charge shifts cost recovery risk from the Company to customers. The Company is being compensated for sales volume-related risks via the rate of return (profit) on its equity. At the time of a general rate case, the Department can examine what costs should be assigned and recovered through the monthly customer charge and what costs should be assigned and recovered in a volumetric charge. The general rate case forum also has the advantage that all the Company's costs, including the return for risk, can be reviewed by more parties than those participating in this proceeding. I also note that cost recovery through a fixed monthly charge was not part of the Company's initial GMP. Rather, the Company added the proposal in the updated GMP after the Department rejected the Company's attempts to shift risk from shareholders to customers through rate changes proposed in the Company's initial GMP.

Q. Do you have any recommendations related to the recovery of GMP-related costs in a fixed customer charge per month?

A. Yes. I recommend the Department order the Company to recover costs from all approved GMP components through a per kilowatt-hour charge, rejecting the Company's proposal to recover approved GMP component costs through a fixed customer charge per month.

Q. Please describe your concerns about the Company's proposed Customer Education and Outreach plan.

A. My critique of the Company's proposed Customer Education and Outreach (CEO) plan is based on two observations. First, a top GMP priority for most customers is the opportunity to lower their electricity bill (via rates with CPP and PTR features, for example). Second, because the AGO recommends that the Department reject the Company's AMF proposals, there is no need for a CEO plan at this time. However, I provide some observations to guide future CEO plans for AMF, CPP, and PTR deployment.

Q. Please describe what your first observation indicates for the Company's proposed CEO plan.

A. Because most customers' GMP priority is bill reduction, the CEO plan should focus the most on the GMP elements that provide the most opportunity for bill reductions—CPP and PTR. Thus, the vast majority of CEO budgets should be focused on CPP/PTR rate features: how they work and what loads customers can manage to benefit from them.

Q. Do you have other recommendations for some future, AMF-related CEO plan?

A. Because not all customers are responsive to utility communications, third parties should play an extensive role to help distribute CPP/PTR-related messages. Organizations trusted by specific customer constituencies, including trade unions, chambers of commerce, religious groups, environmental groups, and the like, could be excellent CPP/PTR marketing partners. I believe these marketing channel partners would increase CPP/PTR participation and behavior change, thereby improving the benefit-cost ratio of an AMF deployment. EDCs could use the success of the Mass Save program as a model for this type of multi-channel communication.

Q. Do you have any recommendation specific to the CEO plan submitted by the Company?

A. Yes. If the Department rejects the Company's AMF proposal, I recommend the Department also reject the Company's proposed CEO. The Company's traditional manner of communicating rate increases – bill stuffers, public notices, social media, and the like – should satisfy any need to provide information about other GMP issues.

Q. Finally, could you please provide your recommendations for the Department on the Company's proposal to offer a Customer Load Management Program?

A. Yes. I appreciate the potential value of Load Management Programs to Customers. However, I do not believe load management programs of the type described by the Company in its GMP necessarily requires AMF. Customer loads can be managed remotely through a variety of technologies; advanced meters need not necessarily serve as the gateway to home energy management. Despite my recommendation that the Company's AMF proposals be rejected, I recommend the Company continue the implementation of load management programs described in its approved Energy Efficiency Three Year Plan. The only caveat to this is my previous recommendation for a Department proceeding to consider the benefits and costs of curtailment services as a competitive offering. If such a proceeding were held, and curtailment services found to be a competitive business not subject to Department regulation, the Company would be required to pursue load management programs through an unregulated subsidiary.

VI. REVIEW, RECOMMENDATIONS, AND CONCLUSION

Q. Please summarize your recommendations for the Department in 15-120.

A. As described further below, I recommend that the Department:

- Reject the Company's AMF deployment plans;
- In the absence of AMF, deem the Company's Customer Education and Outreach plan unnecessary; and
- Implement conditions for any GMP components the Department might approve which would improve overall GMP reasonableness and the benefit-cost ratio for customers.

Q. Please review why you believe the Department should reject AMF deployment in the Company's service territory.

A. My testimony indicates that the Department should reject the Company's AMF plan because, in order to maximize peak demand response benefits, Massachusetts must address these challenges:

- CPP/PTR rate features are limited to Basic Service, a shrinking customer class;
- ISO-NE capacity market designs do not adequately value summer residential demand response;
- Further clarity on data access (and third party involvement in demand response) is required; and
- Further clarity on CPP/PTR rate designs, event processes, and offers is required.

Q. Do you have any recommendations on how the Department should resolve these issues?

A. Yes. Prior to AMF deployment, I believe the Department should conduct proceedings to consider:

- The potential expansion of PTR to all customers regardless of source of supply;
- Data access requirements for demand response, including the potential for competitive service suppliers, data access needs, and infrastructure implications; and
- Specific requirements for CPP/PTR rate designs, event processes, and EDC offers.

On this last point, potential modifications to the ISO-New England capacity market could prove helpful in maximizing the value of seasonal demand response programs, and will absolutely impact CPP/PTR rate designs. I recommend interested stakeholders pursue capacity market product designs which more appropriately value residential summer (and winter) load reduction potential with ISO-New England.

Q. Please review why you believe the Company's Customer Education and Outreach (CEO) plan should be deemed unnecessary.

A. If the Department rejects the Company's AMF proposal, a CEO plan is unnecessary.

Q. Do you have any recommendations for future CEO plans?

Yes. I believe future CEO plans should:

- Be focused almost exclusively on CPP/PTR rate participation and behavior change; and
- Utilize non-utility channels with high levels of trust among customer constituencies to distribute CPP/PTR messages.

Q. Please review your concerns regarding the overall reasonableness of the Company's GMP, including those related to grid-facing as well as customer-facing components.

A. I have several concerns regarding the overall reasonableness of the Company's GMP which will reduce the customer benefit-cost ratio of any components approved by the Department.

- The risk for cost overruns falls disproportionately on ratepayers;
- There are insufficient assurances that anticipated benefits will be achieved;
- The Company can "time" rate cases such that GMP-related operating cost reduction benefits fall to shareholders, not ratepayers;
- If the Department departs from past precedent, the Company will profit on any in-service assets stranded by grid modernization and profit on approved GMP investments as well; and
- Without specific Department action, the Company's proposals shift risk from shareholders to customers through "tracker" recovery of O&M costs and through recovery of costs for approved GMP components through a fixed monthly customer charge.

Q. Do you have any recommendations on how the Department should resolve these concerns?

A. Yes.

- The Company should be held accountable for cost overruns on GMP capabilities approved by the Department, with any excess over projections split 50:50 between shareholders and ratepayers;
- The Department should establish a mechanism which reflects in customer rates, perhaps through a reduction in tracker revenue requirements, projected operating expense reductions for GMP capabilities approved by the Department;
- For each approved GMP component, the Department should establish outcome-based performance metrics, pre-deployment baseline measures, targets, interim and ultimate timeframes for achievement, and reporting requirements;
- As a matter of policy, and consistent with past precedent, the Department should prohibit the Company from recovering profits on stranded assets, and that the stranded costs be recovered over the same timeframe over which benefits to customers are generated from the modern grid investments which caused the assets to be stranded (retired prematurely);
- As a matter of policy, the Department should prohibit the recovery of O&M costs through any mechanism other than a general rate case, including the instance of this GMP; and
- As a matter of policy, the Department should prohibit increases in fixed monthly customer charges through any mechanism other than a general rate case, including the instance of this GMP.

Q. Do you have any concluding remarks?

A. Yes. I believe grid modernization, and AMF specifically, offers a potentially favorable benefit-cost ratio to customers. However, to secure a favorable benefit-cost ratio, I believe conditions must be suitable, utilities must be motivated, regulators must oversee, and customers must participate. The Department's orders in D.P.U. 12-76-B and D.P.U. 14-04-C represent a pragmatic and innovative approach to grid modernization in general, and to the default application of peak demand response rate features in particular. I encourage the Department to continue with this approach, as I believe it is crucial to achieving a favorable AMF benefit-cost ratio for Massachusetts electric customers.

Q. Does this conclude your testimony?

A. Yes, it does.

APPENDIX A: CURRICULUM VITAE OF PAUL ALVAREZ

Curriculum Vitae -- Paul J. Alvarez MM, NPDP

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Profile

After 15 years in Fortune 500 product development and product management, including P&L responsibility, Mr. Alvarez entered the utility industry by way of demand-side management rate and program development, marketing, and impact measurement in 2001. He has since designed renewable portfolio standard compliance and distributed generation rates and incentive programs. These experiences led to unique projects involving the measurement of grid modernization costs and benefits (energy, capacity, operating savings, revenue capture, reliability, environmental, and customer experience), which revealed the limitations of current utility regulatory and governance models. Mr. Alvarez currently serves as the President of the Wired Group, a boutique consultancy serving consumer and environmental advocates, regulators, associations, and suppliers.

Research Projects, Thought Leadership, Regulatory Appearances

Arguments to Reject Duke Energy Kentucky's CPCN for a $49 Million Smart Meter Investment in Favor of Reconsideration in a Rate Case. Testimony before the Kentucky Public Service Commission on behalf of the Office of Attorney General, 2016-00152. July 18, 2016

Arguments to Reject Pacific Gas & Electric's Request to Invest $100 Million in Its Grid to Accommodate Distributed Energy Resources. Testimony before the California Public Utilities Commission on behalf of The Utility Reform Network, A15-09-001. April 29, 2016

Arguments to Reject Westar Energy's Proposal to Mandate a Rate Specific to Distributed Generation-Owning Customers. Testimony before the Kansas Corporation Commission on behalf of the Environmental Defense Fund, case 15-WSEE-115-RTS. July 9, 2015.

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Duke Energy Ohio Smart Grid Audit and Assessment. Primary research report prepared for the Public Utilities Commission of Ohio case 10-2326-GE. June 30, 2011.

SmartGridCity™ Demonstration Project Evaluation Summary. Primary research report prepared for Xcel Energy. Colorado Public Utilities Commission case 11A-1001E. Filed December 14, 2011 as Exhibit MGL-1. Report dated October 21, 2011.

Books

Smart Grid Hype & Reality: A Systems Approach to Maximizing Customer Return on Utility Investment. First edition. ISBN 978-0-615-88795-1. Wired Group Publishing. 327 pages. 2014.

Noteworthy Publications

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Maximizing Customer Benefits: Performance Measurement and Action Steps for Smart Grid Investments. Public Utilities Fortnightly. January, 2012.

Buying Into Solar: Rewards, Challenges, and Options for Rate-Based Investments. Public Utilities Fortnightly. December, 2009.

Smart Grid Regulation: Why Should We Switch to Performance-based Compensation? Smart Grid News. August 15, 2014.

A Better Way to Recover Smart Grid Costs. Smart Grid News. September 3, 2014.

Is This the Future? Simple Methods for Smart Grid Regulation. Smart Grid News. October 2, 2014.

The True Cost of Smart Grid Capabilities. Intelligent Utility. June 30, 2014.

Notable Presentations

NASUCA Mid-Year Meeting. *Utility Evaluator™ Software: Benchmarking Distribution Utility Performance Using Publicly-Available Data.* New Orleans, LA. June 7, 2016.

NARUC Committee on Energy Resources and the Environment. *How big data can lead to better decisions for utilities, customers, and regulators***.** Washington DC. February 15, 2016.

National Conference of Regulatory Attorneys 2014 Annual Meeting. *Smart Grid Hype & Reality.* Columbus, Ohio. June 16, 2014.

NASUCA 2013 Annual Conference. *A Review and Synthesis of Research on Smart Grid Benefits and Costs.* Orlando. November 18, 2013.

NARUC Subcommittee on Energy Resources and the Environment. *The Distributed Generation (R)Evolution.* Orlando. November 17, 2013.

IEEE Power and Energy Society, ISGT 2013. *Distribution Performance Measures that Drive Customer Benefits.* Washington DC. February 26, 2013.

Canadian Electric Institute 2013 Annual Distribution Conference. *The (Smart Grid) Story So Far: Costs, Benefits, Risks, Best Practices, and Missed Opportunities.* Keynote. Toronto, Canada. January 23, 2013.

Great Lakes Smart Grid Symposium. *What Smart Grid Deployment Evaluations are Telling Us.* Chicago. September 26, 2012.

Mid-Atlantic Distributed Resource Initiative. *Smart Grid Deployment Evaluations: Findings and Implications for Regulators and Utilities.* Philadelphia. April 20, 2012.

DistribuTECH 2012. *Lessons Learned: Utility and Regulator Perspectives.* Panel Moderator. January 25, 2012.

DistribuTECH 2012. *Optimizing the Value of Smart Grid Investments.* Half-day course. January 23, 2012.

NARUC Subcommittee on Electricity. *Maximizing Smart Grid Customer Benefits: Measurement and Other Implications for Investor-Owned Utilities and Regulators.* St. Louis. November 13, 2011.

Teaching

Post-graduate Adjunct Professor. University of Colorado, Global Energy Management Program. Course: Renewable Energy Commercialization: Electric Technologies, Markets, and Policy.

Guest Lecturer. Michigan State University, Institute for Public Utilities. Courses: Performance Measurement of Distribution Utility Businesses; Introduction to Grid Modernization.

Education

Master of Management, 1991, Kellogg School of Management, Northwestern University. Concentrations: Accounting, Finance, Information Systems, and International Business.

Bachelor's Degree in Business Administration, 1984, Kelley School of Business, Indiana University. Concentrations: Marketing and Finance.

Certifications

New Product Development Professional. Product Development and Management Association. 2007.