APPENDIX AND SCHEDULES

Appendix

APPENDIX A	CURRICULUM VITAE OF PAUL J. ALVAREZ

Schedules

Schedule PJA-1	Staff DR TS-011. Attachment TS 1-011A
Schedule PJA-2	Staff DR 10-003
Schedule PJA-3	OCA DR TS 1-003
Schedule PJA-4	OCA TS 1-004
Schedule PJA-5	OCA DR TS 1-001(a-d)
Schedule PJA-6	Staff DR 10-004, Attachment Staff 10-004
Schedule PJA-7	OCA DR 6-087(a)
Schedule PJA-8	Letter from Thomas Frantz of Staff to Dan Comer of PSNH dated July 24, 2017 regarding a meeting held July 17, 2017. Provided by PSNH in response to OCA DR 6-084.
Schedule PJA-9	OCA DR 6-085
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Schedule PJA-11	OCA DR TS 1-007, Attachment OCA TS 1-007 A

APPENDIX A: CURRICULUM VITAE OF PAUL J. ALVAREZ

Wired Group, PO Box 620756, Littleton, CO 80162. palvarez@wiredgroup.net 303-997-0317

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 for Xcel Energy 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.

Appearances and Research Projects in Regulatory Proceedings

Critique of Smart Meter Benefits Claimed by Puget Sound Energy. Testimony before the Washington Utility and Telecom Commission recommending rejection of cost recovery pending demonstration of benefits in excess of costs. UE-190529 and UG-190530. November 22, 2019.

Critique of Smart Meter Benefits Claimed by Rockland Electric Company. Testimony before the New Jersey Board of Public Utilities on behalf of the Division of Consumer Advocate recommending rejection of cost recovery pending demonstration of benefits in excess of costs. ER19050552. October 11, 2019.

Critique of Grid Improvement Plan Proposed by Indianapolis Power and Light. Testimony before the Indiana Utility Regulatory Commission recommending reductions in the size of the plan ($1.2 billion) based on benefit-cost analyses of plan components. Cause 45264. October 7, 2019.

Investigation into Distribution Planning Processes. Comments to the Michigan Public Service Commission recommending a transparent, stakeholder-engaged distribution planning process. U-20147. September 11, 2019.

Investigation into Grid Modernization. Comments to the New Hampshire Public Utilities Commission recommending a transparent, stakeholder-engaged distribution planning process. IR 15-296. September 6, 2019.

Arguments to Reduce and Re-prioritize Grid Modernization Investments Proposed by Pacific Gas & Electric. Testimony before the California Public Utilities Commission. A.18-12-009. July 26, 2019.

Evaluation of Xcel Energy's Request for an Advance Determination of Prudence Regarding Natural Gas Generation Plant Purchase. Testimony before the North Dakota Public Service Commission. PU-18-403. May 28, 2019.

Critique of Smart Meter Replacement Program Implied by Proposed Duke Energy Ohio Global Settlement Agreement. Testimony before the Public Utilities Commission of Ohio on behalf of the Office of Consumer Counsel. Numerous cases including 17-0032-EL-AIR. June 25, 2018.

Support for Considering Duke Energy Grid Modernization Investments in a Distinct Proceeding. Testimony before the North Carolina Utilities Commission on behalf of the Environmental Defense Fund. E-2 Sub 1142, October 18, 2017 and E-7 Sub 1146, January 19, 2018.

Evaluation of Southern California Edison's Request to Invest $2.3 Billion in its Grid to Accommodate Distributed Energy Resources. Testimony before the California Public Utilities Commission on behalf of The Utility Reform Network. A16-09-001. May 2, 2017.

Evaluation of Kentucky Utilities/Louisville Gas & Electric Smart Meter Deployment Plan. Testimony before the Kentucky Public Service Commission on behalf of the Kentucky Attorney General in 2016-00370/2016-00371. March 3, 2017. Also in 2018-00005 May 18, 2018

Evaluation of National Grid's Massachusetts Smart Meter Deployment Plan. Testimony before the Massachusetts Department of Public Utilities on behalf of the Massachusetts Attorney General in 15-120. March 10, 2017.

Evaluation of 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

Recommendations on Metropolitan Edison's Grid Modernization Plan. Testimony before the Pennsylvania Public Utilities Commission on behalf of the Environmental Defense Fund in R-2016-2547449. July 21, 2016.

Arguments to Consider Duke Energy's Smart Meter CPCN in the Context of a Rate Case. Testimony before the Kentucky Public Service Commission on behalf of the Attorney General in 2016-00152. July 18, 2016.

Evaluation of 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.

Regulatory Reform Proposal to Base a Significant Portion of Utility Compensation on Performance in the Public Interest. Testimony before the Maryland PSC on behalf of the Coalition for Utility Reform, case 9361. December 8, 2014.

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

SmartGridCity™ Demonstration Project Evaluation Summary. Primary research and report prepared for Xcel Energy. Colorado Public Utilities Commission case 11A-1001E. October 21, 2011.

Books

Smart Grid Hype & Reality: A Systems Approach to Maximizing Customer Return on Utility Investment. Second edition. ISBN 978-0-615-88795-1. Wired Group Publishing. 360 pages. 2018.

Noteworthy Publications

The Rush to Modernize: An Editorial on Distribution Planning and Performance Measurement. With Sean Ericson and Dennis Stephens. Public Utilities Fortnightly. July 8, 2019. Pages 116+

Modernizing the Grid in the Public Interest: Getting a Smarter Grid at the Least Cost for South Carolina Customers. Whitepaper co-authored with Dennis Stephens for GridLab. January 31, 2019

Modernizing the Grid in the Public Interest: A Guide for Virginia Stakeholders. Whitepaper co-authored with Dennis Stephens for GridLab. October 5, 2018.

Measuring Distribution Performance? Benchmarking Warrants Your Attention. With Sean Ericson. Electricity Journal. Volume 31 (April, 2018), pages 1-6.

Busting Myths: Investor-Owned Utility Performance Can be Credibly Benchmarked. With Joel Leonard. Electricity Journal. Volume 30 (October, 2017), pages 45-48.

Price Cap Electric Ratemaking: Does it Merit Consideration? With Bill Steele. Electricity Journal. Volume 30, (October, 2017), pages 1-7.

Integrated Distribution Planning: An Idea Whose Time has Come. Public Utilities Fortnightly. November, 2014; also International Confederation of Energy Regulators Chronicle, 3rd Ed, March, 2015

Smart Grid Economic and Environmental Benefits: A Review and Synthesis of Research on Smart Grid Benefits and Costs. Secondary research report prepared for the Smart Grid Consumer Collaborative. October 8, 2013. Companion piece: Smart Grid Technical and Economic Concepts for Consumers.

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

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

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

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

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.

Notable Presentations

NASUCA Annual Meeting. *Reinventing Distribution Planning in New Hampshire.* With D. Maurice Kreis, Executive Director, Office of Consumer Advocate. San Antonio, TX. November 19, 2019.

National Council on Electricity Policy Annual Meeting. Trainer on the economics of distribution grid interoperability and standard compliance; Presentation on communication network economics. Austin, TX. Sept 10-12, 2019.

NASUCA Annual Meeting. *Grid Modernization: Basic Technical Challenges Advocates Should Assert.* Orlando, FL. November 13, 2018.

Illinois Commerce Commission, NextGrid Working Group 7. *Using Peer Comparisons in Distributor Performance Evaluation.* Workshop 3 Presentation. Chicago, IL. July 30, 2018.

NARUC Committee on Electricity. *Using Peer Comparisons in Distributor Performance Evaluation.* Smart Money in Grid Modernization Panel Presentation. Scottsdale, AZ. July 16, 2018.

Public Utilities Commission of Ohio, Power Forward Proceeding Phase 2. *Getting a Smart Grid for FREE.* Columbus, Ohio. July 26, 2017.

NASUCA Mid-Year Meeting. *Using Performance Benchmarking to Gain Leverage in an "Infrastructure Oriented" Environment.* Denver, CO. June 6, 2017.

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, FL. November 18, 2013.

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

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

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

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

Canadian Electric Institute 2013 Annual Distribution Conference. *The (Smart Grid) Story So Far: Costs, Benefits, Risks, Best Practices, and Missed Opportunities.* Toronto, Canada. January 23, 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's Degree in Management, 1991, Kellogg School of Management, Northwestern University. Concentrations: Finance, Accounting, Information Systems, and International Business.

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

Certifications

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

The AMR solution is lowest cost, and attains the majority of the potential savings

PSNH Automated Meter Reading Cost Comparison *($000's)*	AMR	"Bridge"	AMI	
Meter Cost (552,000 meters)	$ 26,801	$ 48,413	$ 75,364	
Meter Installation Cost	$ 9,172	$ 9,172	$ 9,172	
Remote Disconnect Switch (37,000)	$ 740	$ 740	Inc.	
Meter Testing	$ 2,238	$ 2,238	$ 2,238	
Project Manager	$ 471	$ 471	$ 471	
IT Cost & Hardware	$ 845	$ 845	$ 25,000	*
Total Requested Capital	$ 40,267	$ 61,879	$ 112,245	
Salvage Value & Avoided Capital	$ (1,322)	$ (1,322)	$ (1,322)	
Net Capital Requirement	$ 38,945	$ 60,557	$ 110,923	
Average Annual O&M Savings	$ 6,700	$ 6,700	$ 10,250	
Total FTE Reduction	57	57	86	
Average Installed Cost Per Meter	$ 70.55	$ 109.70	$ 202.29	

* AMI IT costs are high level and may not be complete.

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Schedule PJA-1

Public Service of New Hampshire d/b/a Eversource Energy
Docket No. DE 19-057

Date Request Received: 08/13/2019 **Date of Response: 09/03/2019**
Request No. STAFF 10-003 **Page 1 of 7**
Request from: New Hampshire Public Utilities Commission Staff

Witness: Penelope Conner

Request:
Reference Conner Testimony. Please provide a detailed explanation of why Eversource chose to replace the meters in NH at that point in time instead of waiting until a later date to install AMR, AMI, or alternative meters?

Response:

Summary:

Below, the Company provides a detailed explanation of the considerations that factored into management's decision to move ahead with AMR implementation. However, the decision rested on two critical conclusions: First, it was time to replace the then-existing meter system due to the system's age and because of the customer and employee benefits that would arise from the implementation of AMR. In fact, the benefits to customers of implementing AMR were so substantial and clear cut, that good business judgment obligated the decision. Second, and conversely, the implementation of an AMI system constituted, at best, a distant possibility for PSNH, requiring resolution of several significant obstacles over a prolonged time period. As a result, holding off on the meter decision awaiting a transition to AMI was not a reasonable option for the interests of customers. In any event, implementation of AMI would require PSNH to maintain a separate metering system during AMI installation and beyond, given that customers must opt into AMI, and AMI may not be feasible or affordable for implementation in rural, mountainous, geographic territories. Therefore, the interests of customers were best served with implementation of AMR beginning in 2013.

Decisional Considerations:

Prior to 2012, PSNH had been evaluating the potential conversion of the manual meter-reading system to an automated system but did not decide to move ahead with the initiative prior to the announcement of the Northeast Utilities/NSTAR merger.

In 2012, following the merger, the Meter Reading organization was asked to resume work on the analysis because it was clear that new, more efficient technology would have significant benefits for customers. By 2012, AMR had already been deployed in Connecticut and Massachusetts for both gas and electric operations for many years with great success in terms of increased operating efficiency and cost savings. AMR was deployed in Connecticut in the early 2000's and was fully deployed in Massachusetts by the 2006-2008 timeframe. The implementation of AMR would standardize processes across all three jurisdictions, lowering operating costs for PSNH customers.

More specifically, in addition to the substantial operating cost savings, there were a number of reasons that the Company found it necessary to transition to AMR, relating to the condition of the then-existing metering system. For example, PSNH considered that the manual meter reading system required use of hand-held meter reading devices (over 100 units), which were in need of replacement because the units were failing and were no longer supported by available meter data collection software, nor were consistent with the meter data collection systems in use across the Northeast Utilities enterprise. With the implementation of AMR, PSNH was able to avoid the unnecessary replacement of the hand-held devices and enable the transition to a common enterprise-wide meter reading platform. Similarly, the legacy meter equipment was aging. As shown in response to OCA 6-089, at the time the decision was made, over 60 percent of the Company's metering equipment was greater than 20 years old and only approximately 10 percent of the meter inventory was within 10 years old.

Other qualitative factors were considered as well, including non-monetary customer benefits. Most significantly, both customers and the Company's Customer Service representatives gain certainty that the meter reading is accurate. When a meter is manually read, there is exposure to increased estimated meter reads due to an inability to access the meter, and a greater potential for error due to a mis-read or mis-key. Estimated meter reads in New Hampshire with a manual system were driven by weather. In fact, during 2016, when the Company actually had a substantial penetration of AMR devices in place during the significant winter weather impacts that occurred, the Company observed a material difference in the number of estimated reads associated with manually read meters and from AMR equipped areas, with the need for estimated reads greatly diminished in the AMR equipped areas.

Customers generally are not satisfied or amenable to estimated reads due to the potential lack of accuracy which leads to the need to calculate and charge a true-up once actual reads are received. Another challenge with manually read systems is the potential for meter-reading errors. For example, when a customer calls with a billing concern, and the meter was manually read, the customer is typically suspicious at the meter read accuracy. These calls are more difficult for customer service representatives to resolve with customers, and customers may request rereads. The move to the new AMR system enabled the Company to enhance the net metering customer experience and to provide a clear and understandable bill to customers. Lastly, customers were happy to avoid the Company's traditional winter "plow" letters. These letters were mailed every fall ahead of the winter weather, reminding customers that PSNH needs to access to the meter for manual reads and that access to the meter must be maintained.

Moreover, the management of the manual metering system involved inherent safety problems for employees who had to access customer premises to obtain readings in remote areas in New Hampshire through the winter season, and in terms of exposure to vehicle-related accidents. In addition, the manual meter system involved a customer convenience consideration, given that the Company had to contact and rely on customers daily to clear pathways to meters in adverse weather conditions. In fact, from an operational perspective, the manual meter reading system was an archaic, resource-draining function that represented a key focal point for improved efficiency in both safety and cost for customers and employees. Therefore, identifying a cost-effective replacement of the manual meter reading system became a priority for management in 2012.

In making major investments, Eversource Energy (then Northeast Utilities), requires the evaluation of project alternatives. The project alternatives for the PSNH AMR Project were identified as the following:

1. AMR with a drive-by collection system.
2. AMR to AMI "Bridge" meters.
3. Full-blown AMI with 2-way communications network to all meters.

Ultimately, the Company determined that AMR was the best solution for customers among other options based on the considerable annual savings anticipated from the conversion; the reasonable payback period; the improvement of safety for PSNH meter-reading employees, the operational efficiencies associated with integration of shared or same applications across companies, and concerns with legal and regulatory issues associated with the "opt in" and the "attempt contact before disconnecting" requirements under New Hampshire law.

In reaching this decision, Northeast Utilities factored in several considerations regarding the cost and feasibility of AMI implementation in general, and in New Hampshire in particular. In short, the implementation of AMI was not viewed as an imminent possibility, nor was it viewed as an alternative with the potential for implementation within a time range where it would make sense to delay the implementation of AMR. The reasons for this determination are as follows:

Considering the Potential for AMI Implementation

In 2012, NSTAR Electric Company ("NSTAR Electric") and Western Massachusetts Electric Company, each operating affiliates within the new Northeast Utilities organization, were immersed in Docket D.P.U. 12-76, before the Massachusetts Department of Public Utilities ("MDPU"). In this docket, the MDPU was conducting an intensive, robust stakeholder process to investigate policy decisions regarding the implementation of advanced metering infrastructure (AMI) and time varying rates ("TVR"). TVRs are necessary to extract the customer-related energy management and conservation savings thought to arise from AMI implementation. Policy initiatives regarding potential AMI implementation were also commencing in Connecticut and New Hampshire. With policy initiatives progressing in all three operating jurisdictions, Northeast Utilities recognized the need to evaluate any and all metering decisions in the context of potential adoption of AMI by the MDPU, but also by the New Hampshire Public Utilities Commission and Public Utility Regulatory Authority in Connecticut.

The research and study undertaken by Northeast Utilities, in which Ms. Conner was thoroughly involved, resulted in the conclusion that the costs of AMI would be very substantial and that the benefits of AMI would not be reasonably achievable in the foreseeable future, particularly in New Hampshire due to certain unique circumstances, and certainly not for many, many years. In 2012-2013, and even today in 2019, Eversource Energy recognizes that there are certain, fundamental complexities inherent in an AMI system (and AMR to AMI bridge meters) that make the transition to AMI a very significant, distant decision for PSNH customers.
The crux of the issue is the cost/benefit tradeoff associated with AMI implementation and operation in New Hampshire. Based on Eversource Energy's knowledge of these complexities; the status of the PSNH distribution system; and customer load profiles, the implementation of AMI in New Hampshire remains many years into the future, even from today's standpoint more than six years after the decision was made to implement AMR in New Hampshire for the benefit of PSNH customers.

The considerations relating to costs and benefits that Northeast Utilities considered, included but were not limited to, the following:

Costs:

- The implementation of AMI involves significantly more than the replacement of meters. An AMI roll-out would require the significant enhancement, replacement or installation of several substantial information systems.
- The information systems that would have to be modified, replaced or developed include:
    - o New Communications Infrastructure to transmit communications from the meter to the Company (data backhaul);
    - o A new Meter Data Management System to collect, store and process interval data;
    - o A new Meter Asset Systems to store information about all advanced metering assets;
    - o A new Customer Information System ("CIS") to calculate and present bills with time varying rates to the customer;
    - o Upgrades to ISO-NE and Load Research Systems to interface with internal metering, CIS and ISO-NE processes; and
    - o Upgrades to the Outage Management System to utilize meter-level data to support restoration efforts; and any company-owned home technology systems, e.g., usage displays and thermostats.
- The Company's call center capabilities would also need to be restructured to address AMI implementation.
- Substantial costs would need to be expended to perform customer outreach, marketing and education campaigns to educate customers as to the mechanics, ramifications and potential benefits of AMI and time varying rates.

Benefits:

There are two areas with the potential to benefit from the implementation of AMI: customers and the distribution system. The primary benefit envisioned for customers arises from the two-way customer communications and the enablement of customer control over energy use, with the ultimate goal being reduced energy consumption and cost. The primary benefit for the distribution system is improved outage management and the enablement of grid-side interconnection of distributed energy resources. More specifically, the benefits enabled in each of these two categories are generally identified as follows:

Customer (with two-way communication through AMI):

Demand response - both appliance & price based.

Provide distributed generation to utilities.

Energy efficiency through real time price awareness.

Operations – (with AMI, SCADA, outage management and system automation)

Ability to network vast numbers of small-scale distributed energy generation and storage devices.

Improved outage management – remote switching.

Improved security.

Theft detection.

Remote connects & disconnects.

Complexities of Cost/Benefit Tradeoff:

Although the goals and objectives of AMI implementation unquestionably resonate in relation to important public policy goals, the practicalities of implementation are critical considerations. Some of the practicalities that create obstacles for the cost-effective implementation of AMI, particularly in New Hampshire are the following:

1. **AMI Would Not Be Feasible for PSNH, Unless Implemented in MA and CT**: In 2012, Northeast Utilities estimated, conservatively, that the price tag for an AMI rollout in Massachusetts would likely exceed $1 billion over the course of the implementation. For New Hampshire, the overall AMI system cost was estimated at more than $137 million exclusive of the communications infrastructure necessary to operate AMI, and assuming that AMI is first implemented for Connecticut and Massachusetts. It was highly unlikely that AMI would be cost-effective or affordable any time in the future on a standalone basis for New Hampshire. This is because the system changes and related costs are simply so substantial that the system would be affordable only if implemented across all three jurisdictions. In 2013, Northeast Utilities did not anticipate that the implementation of AMI for Connecticut and/or Massachusetts was either imminent or on the horizon over the next many years.

2. **Data Capture, Storage, Management and Presentment Creates Substantial Challenges**: The key value (and characteristic) of AMI is two-way communication between the customer and the Company. More specifically, the value of AMI is derived through real-time, or near real-time, collection of interval data for each individual customer on the system. However, the sheer volume of data that would need to be captured, securely stored and managed, and prepared for presentment to customers would create astronomical operating challenges that are costly and complex to resolve.

For example, during the D.P.U. 12-76 proceeding, Northeast Utilities calculated that, if NSTAR Electric were required to collect customer data in one-minute intervals, it would collect 2.16 trillion data points per month and, assuming that the then-current rate of one to two percent billing exceptions per month continued, NSTAR Electric would have needed to hire between 200 and 300 FTEs to address the 43.2 billion billing exceptions estimated to occur per month. Similarly, Baltimore Gas and Electric Company needed to hire over 80 FTEs to address the significant increase in billing exceptions, which flowed from its implementation of AMI and the subsequent increase in customer data collected on a monthly basis. Northeast Utilities further estimated that, collecting the data in 15-minute intervals would result in 540 billion data points per month as compared to approximately 7 million data points currently then-collected.

If data is not collected on a frequent interval, the benefits associated with TVR and customer management of their energy usage cannot be obtained. However, the direct and indirect costs associated with developing and using these capabilities are sizeable. As a result, the need to develop thee capability to capture, securely store and manage, and present the data to customers is a significant obstacle to overcome.

3. **Customer Load Profiles Do Not Create Sufficient Opportunity**: A second important practicality considered by Northeast Utilities is the fact that residential customers do not have the discretionary load to shift, resulting in an immaterial, if any, opportunity to realize sufficient bill savings to warrant the cost of AMI. The lack of air conditioning load in New England is one of the driving factors behind this conclusion. For example, central air conditioning penetration in NSTAR Electric's service territory was approximately 38 percent in 2012, occurring in only two to three months per year, as compared to

significantly higher penetration in warmer states, such as the 60 to 80 percent penetration in Baltimore Gas and Electric's service territory in Maryland.

Based on research performed by Northeast Utilities in 2012, there were only approximately 4,000 homes in NSTAR Electric's service territory with enough discretionary load to shift to reap the benefits associated with AMI/TVR (out of a customer base of approximately 1.1 million customers). Given the low penetration rates and the concurrently small discretionary load to shift, residential customer savings would be relatively insignificant. For example, in 2012, a residential customer in the NSTAR Electric territory with a four-bedroom home, central air conditioning, and a 1,657 average monthly kWh usage would save approximately $161 annually on a $3,500 annual bill (5 percent savings) if that customer reacted to price signals under a hypothetical TVR by curtailing air conditioning usage. Customers with even lower levels of discretionary load, e.g. those without air conditioning, would see even fewer, if any, savings.

Similarly, Northeast Utilities' experience was that small commercial customers also lacked operational flexibility to shift load, as demonstrated by a small commercial and industrial ("C&I") TVR pilot conducted in CL&P's service territory prior to 2012. CL&P reported that, for a critical peak price rate, small C&I pilot participants' response was only 18 percent of that observed for residential customers, while for the peak time rebate and the time-of use rate, participants showed no statistical response. Furthermore, some required behavioral changes, such as reducing lighting and/or air conditioning during peak times, associated with TVR could have a negative impact on small businesses.

Such modest savings, assuming customers were able to achieve them given their limited discretionary load, would not sufficiently offset the estimated costs associated with the deployment of AMI, delaying implementation of AMI to the future.

4. **Energy Cost Reductions from AMI Require Time Varying Rates**: TVR, in general, is a complex concept worthy of in-depth analysis and consideration. Implementation of TVR would require work and investment by numerous interdependent Northeast Utilities business departments, including the customer care, billing, rates and regulatory and engineering departments. These departments, with their specific expertise, would need to participate in the development of a Company-specific proposal, including but not limited to the type and design of a TVR mechanism that would best achieve grid modernization goals; which rate classes would be affected; whether TVR would be mandatory and, if so, for which rate classes; and how best to educate customers as to the opportunities and mechanics of the proposed TVR mechanism. Similarly, all of these issues would need to be reviewed, evaluated and determined by regulators in Massachusetts, Connecticut and New Hampshire, which Northeast Utilities recognized would be years in the making (and has yet to occur). Without final determinations regarding TVR, final determinations regarding the cost/benefit equation for AMI cannot be resolved.

5. **Distributed Energy Resources Are Not Sufficient to Derive Operational Benefits from AMI**: The benefit of AMI to the distribution system is derived through better visibility into the distributed energy generation and storage devices interconnected to the distribution system. In 2012, both Massachusetts and Connecticut were experiencing the proliferation of distributed energy resources on the electric distribution systems. However, in 2012 and continuing today, the interconnection of distributed energy generation is occurring much more slowly in New Hampshire and it will take substantial time for the penetration of distributed energy resources to reach the level necessary to drive AMI benefits. In part, the penetration of distributed energy resources in New Hampshire is restricted due to the fact that the distribution system remains largely comprised of outmoded delivery infrastructure that will need to be modernized and updated before distributed energy resources may be integrated to the scale that would make AMI beneficial.

6. **A Second Metering System Would Have to Be Maintained in Any Event:** If and when the roll-out of AMI is undertaken, it will not be accomplished instantaneously, nor with complete application to all customers. Under New Hampshire law in place in 2013, customers must "opt in" to AMI participation. Although the Company would reasonably expect that PSNH customers would generally opt to participate, other jurisdictions that have implemented AMI have experienced customer subscription in the range of approximately 80 percent, making it necessary to maintain a separate system for approximately 20 percent of the customer base. Therefore, in any event, a second system would be necessary. Northeast Utilities recognized that implementation of AMR would serve as an appropriate alternative for the AMI back-up system.

Weighed against these considerations, the advantage of implementing AMR for customers beginning in 2013 was clear, particularly given the substantial operating expense reductions available through this option, which would inure to the benefit of customer each year until such time that AMI might be implemented. In the Company's best judgment, passing on the sizeable cost savings and efficiency and safety improvement for an event to occur of speculative benefit and indeterminate timing would be detrimental to the interests of customers and was an unjustifiable project option.

Public Service of New Hampshire d/b/a Eversource Energy
Docket No. DE 19-057

Date Request Received: 10/25/2019 **Date of Response: 11/14/2019**
Request No. OCA TS 1-003 **Page 1 of 1**
Request from: Office of Consumer Advocate

Witness: Penelope Conner

Request:
Refer to Eversource's response to Staff 10-003, page 2, which describes the non-quantitative factors which led Eversource to a decision to replace its meters. f. Quantify the number of customers requesting a meter re-read in 2013, 2014, and 2015. g. Quantify the number of customer complaints registered regarding bills calculated from an estimated meter reading in 2013, 2014, and 2015. h. Quantify the number of customer complaints registered regarding autumn "plow letters" in 2013, 2014, and 2015.

Response:
As discussed and responded to at the 10/28/2019 Technical Session, this data is not available. At the time of the decision to implement AMR, Ms. Conner had oversight and responsibility for the project. The information she has provided regarding customer complaints and "plow letters" is based on her personal knowledge and experience from that time period.

Public Service of New Hampshire d/b/a Eversource Energy
Docket No. DE 19-057

Date Request Received: 10/25/2019 **Date of Response: 11/14/2019**
Request No. OCA TS 1-004
Request from: Office of Consumer Advocate

Witness: Penelope Conner

Request:
Refer to Eversource's response to Staff 10-003, page 1, which states "By 2012, AMR had already been deployed in Connecticut and Massachusetts for both gas and electric operations for many years with great success in terms of increased operating efficiency and cost savings. AMR was deployed in Connecticut in the early 2000's and was fully deployed in Massachusetts by the 2006-2008 timeframe. The implementation of AMR would standardize processes across all three jurisdictions, lowering operating costs for PSNH customers."
a. Describe the AMR system deployed in Connecticut. Include the makes and model numbers of installed equipment and the ongoing business processes involved. b. Describe the AMR system deployed in Massachusetts. Include the makes and model numbers of installed equipment and the ongoing business processes involved. c. The Consumer Advocate understands Eversource provides residential natural gas distribution services in Massachusetts. Describe the AMR system deployed in Massachusetts for natural gas meters, including the makes and model numbers of installed equipment and the ongoing business processes involved. d. Provide the year in which AMR for natural gas meters in Massachusetts was completed. e. Quantify the amount by which standardizing processes across all three jurisdictions would lower operating costs for PSNH customers. Provide all workpapers showing how this estimate was derived.

Response:
a) The AMR system currently deployed in the state of Connecticut is the Itron Field Service Collection System (FCS). The FCS system equipment installed in the AMR vehicles is purchased through ITRON and includes a Panasonic Model CF-31 laptop, coupled with the Itron MC3 radio and vehicle roof top antenna. The electric meters read by the AMR vehicles are those that contain an AMR module utilizing Itron's proprietary SCM or SCM+ protocol. This would include:

- Itron mechanical meters with either R200 or R300 AMR modules
- GE (now Aclara), ABB (now Honeywell), Landis+Gyr mechanical meters with 40E AMR modules
- Itron solid-state Centron and Sentinel meters with R200, R300, or R400 AMR modules
- Itron solid-state Centron meters with dual SCM/Openway (Bridge) AMR modules
- GE, Landis+Gyr solid-state meters with 40E AMR modules.
- Vision solid-state meters with R300 "ERT equivalent" AMR modules

The Monthly drive-by Meter Reading process using FCS in CT is described below:

1. Data download of meters to be read from legacy billing system is imported into FCS for distribution to the computer in the AMR vehicle

2. AMR meters providing consumption values transmit to the AMR vehicle in “drive-by” mode
3. Data collected via FCS is then uploaded from the computer in AMR vehicle using the Company data network at a company facility to the legacy billing system

b) The AMR system currently deployed in the state of Massachusetts is the Itron Field Service Collection System (FCS). The FCS system equipment installed in the AMR vehicles is purchased through ITRON and includes a Panasonic Model CF-31 laptop, coupled with the Itron MC3 radio and vehicle roof top antenna. The electric meters read by the AMR vehicles include the same types as those listed for CT.

The Monthly drive-by Meter Reading process using FCS in MA is also the same as CT described above.

c) Natural gas AMR meters in Massachusetts are read using the same FCS system and process used for electric AMR meters defined in b) above. The download and upload files in the meter reading process are inclusive of both gas and electric AMR meters. The gas meters read by the AMR vehicles are those that contain either Itron’s 40G or 100G AMR module both of which utilize Itron’s proprietary SCM or SCM+ signal protocol.

d) AMR for natural gas meters in Massachusetts was completed in 1996. At that time an earlier version of the Itron AMR system was used, the Itron PremierPlus 4 AMR system (“P4”).

e) Refer to page 4 on Attachment TS 1-011 A, where the “Average Annual O&M Savings” are shown as $6.7M. This is the primary reduction in operating costs which was delivered with the standardization.

Public Service of New Hampshire d/b/a Eversource Energy
Docket No. DE 19-057

Date Request Received: 10/25/2019 **Date of Response: 11/14/2019**
Request No. OCA TS 1-001 **Page 1 of 2**
Request from: Office of Consumer Advocate

Witness: Penelope Conner

Request:
The Consumer Advocate is aware of meter reading modules which can be attached to legacy, installed electric and gas meters to provide for one-way wireless communications to read meters. Such modules can be read by radio-equipped vehicles which drive through neighborhoods, and do not require legacy meters to be replaced. a. Did Eversource consider adding automated meter reading modules as an alternative to meter replacement? If not, why not? b. Provide any analysis Eversource completed regarding the costs and benefits of the option to add meter reading modules. c. Provide any analysis Eversource completed which compare the costs and benefits of the “add module” approach to enabling AMR to the “replace meters” option to enabling AMR Eversource implemented. d. What incremental benefits did Eversource anticipate by replacing it existing meters rather than simply adding the drive-by modules to the existing meters? Please describe and provide a quantified estimate of these incremental benefits, along with all workpapers used to develop the quantified estimate. e. The Consumer Advocate is aware that the remote disconnect/reconnect switch was only added to 37,000 meters per Attachment A, page 11. Did Eversource consider replacing only these 37,000 meters to enable the switch option, instead of replacing all 552,000 meters? If not, why not? What additional benefits did Eversource secure for the 515,000 new meters installed without the switch? Please describe and provide a quantified estimate of these incremental benefits, along with all workpapers used to develop the quantified estimate.

Response:

a) The Company did not investigate nor consider the Module (“ERT” = Electronic Radio Transmitter) approach for an automated meter reading system for two main reasons. First, the ERT is a unit that attaches to the meter. However the bulk of the underlying meter assets were older than 20 years and approaching end of life. The handheld units necessary to read the analog meters were also in need of replacement. Therefore, it would not have made sense to "touch" every meter to install an ERT and not replace the meter, which was necessary or would have been necessary within a relatively short time period of installing the ERT. In other words, the ERT is not a substitute for the meter. The ERT is a mechanism that allows for drive-by meter reads and is only so good as the meter it is sitting on. Second, the Company has had poor experience with these types of units and does not regard the units as a worthy substitute for AMR meters, knowing that the meter equipment (and handheld meter-reading units) were becoming obsolete. Lastly, the Company went through an extensive RFP process for the meter purchases and installation services for the AMR project and none of the vendors who were qualified for consideration offered such modules or solutions.

b) The Company did not perform any analysis on the stand-alone ERT because the ERT is not a substitute for the meter equipment.

c) The Company did not perform any analysis on the stand-alone ERT because the ERT is not a substitute for the meter equipment. Moreover, at about $33 per meter for the new AMR meters, it is very likely that the total cost to equip a mechanical meter with a stand-alone ERT would be similar to the installation of a new AMR meter. In addition, at the time mechanical/manual read meters were approaching the end of their useful life so solutions that may have existed from alternate vendors would not likely have been supported for any extended period of time. The would add risk and cost in the longer term.

d) The Company did not perform any analysis on the stand-alone ERT because the ERT is not a substitute for the meter equipment.

e) The Company had estimated as many as 37,000 service switch meters being installed, but far fewer were actually installed as we currently have about 26,500 in service (note: count of 18,195 previously provided in Staff 12-052 was incorrect as it inadvertently omitted the full FM25S class of service switch meters). The service switch functionality allows "curb-side" (rather than fully remote) disconnection and are deployed in unsafe and difficult to access locations. Due to the increased expense of service switch equipped meters with no direct additional benefit where not "unsafe or difficult to access", the Company did not consider replacing all meters with a service switch equipped meter. The additional benefits secured for the non-service switch equipped meters is the ability to read them via AMR. Those incremental benefits are defined on page 4 on attachment "Q -TS 011 A 2013-05-13 AMR Project – PSNH Presentation" in the prior response to TS-011 where the "Average Annual O&M Savings" are shown as $6.7M.

Public Service of New Hampshire d/b/a Eversource Energy
Docket No. DE 19-057

Date Request Received: 08/13/2019 **Date of Response: 09/03/2019**
Request No. OCA 6-087 **Page 1 of 1**
Request from: Office of Consumer Advocate

Witness: Penelope Conner

Request:
Reference McLean Conner Testimony, Bates 785, Lines 7-9, stating "the AMR option deployed by the Company in 2013 was a solution that was fully and substantially cost justified as a basis for transitioning away from manual meter reading."

a. Please explain whether the Company's AMR meters are capable offering customers a time of use rate and why.
b. Please explain the expected useful life of the Company's existing meters.

Response:

A. The standard AMR meter used in New Hampshire is not capable of measuring Time of Use KWH. The AMR meters strictly measure total usage for the billing period. There is a Time of Use meter in use in New Hampshire for TOU customers. AMR meters are not used for capturing interval data.

B. It is expected that the AMR meters will have a 20 to 25 year life in practice. This assumption is based partially on the the fact that the manufacturers' information for bridge meters is that the non-replaceable battery installed in the meter (demand and remote disconnect meters) will have a 20-year life. The standard AMR meter does not have a battery, so the expected life of the meter is not dependent on battery life.

Public Service of New Hampshire

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The Northeast Utilities System

August 15, 2013

Thomas C. Frantz
Director – Electric Division
NH Public Utilities Commission
21 South Fruit Street, Suite 10
Concord, NH 03301-2429

Dear Mr. Frantz,

Thank you for your letter of July 24, 2013 in which the Staff supported our requests related to several items in PSNH's upcoming Automated Meter Reading (AMR) project. In that letter, you also expressed some concerns related to the lack of integration of the new meters into our future Outage Management System (OMS), and potential risk to the company related to cost recovery for the AMR meters that are not upgradable to a full AMI system in the future. The purpose of this letter is to provide some background on both of those issues to alleviate the concerns of Staff as best we can.

As you know, the AMR meters that we plan to install will not communicate with our new OMS system, just as our current manual meters would not. PSNH will continue to rely upon customers to call us to report power outages at their locations. Although this process of outage notification will remain, there are other enhancements that are being developed and implemented that will improve information flow within the Company and with our customers and that are targeted towards improving outage restoration. These enhancements include the Geographic Information System (GIS) which will serve as the foundation for the OMS, as well as an engineering and reliability analysis tool. The GIS project continues to make substantial progress and will be completed by the fourth quarter of 2013. PSNH has also made substantial improvements to its Trouble Reporting /Trouble Analysis System (TRS & TAS) designed to automate the processing of incoming trouble information to expedite the analysis and planning for a timely and safe restoration effort in the event of a major storm.

In regards to the issue of why PSNH has chosen to install an AMR system rather than an AMI system or a "hybrid" meter that can potentially be converted to an AMI system in the future, I offer the following information. A team of employees from the NU system began to look at automated metering options for PSNH in October 2012. The team reviewed three primary solutions to the automation of PSNH meter reading.

1. An AMR system
2. An AMR/AMI "Bridge" option
3. A full AMI system

The first and lowest cost option brings PSNH on par with the other NU companies by installing a system utilizing AMR meters and drive-by vehicles to obtain the monthly meter readings. This solution leverages past NU integration efforts which have successfully assimilated the AMR meter data into the NU legacy C2 billing system and MDM. These systems utilize meters that send a low level radio signal that is picked up by a receiver mounted in a vehicle as it drives near the meter. Typically, readings are obtained just once a month in these systems.

The second "Bridge" option reviewed by the study team came to light to address an industry wide cost justification problem. In some areas of the US, certain utilities who installed drive-by AMR systems in the past are now looking to convert from AMR to the more advanced AMI system, capable of 2-way communication. Most of these companies are now facing a situation where they are unable to justify the expense of replacing the AMR meters with AMI meters. CL&P also found this to be an obstacle in the financial justification of AMI when it completed a study in 2010. One meter manufacturer (Itron) is now beginning to develop an option for this situation by creating what is sometimes referred to as a "Bridge" meter. In simplest terms, this meter has the capability to be remotely read like other AMR meters, and when the utility wants to convert to AMI, it can convert the meter to 2-way communications without the cost of replacing the physical meter with a new one. If a company has these "Bridge" meters installed, then the AMI costs at that point become focused on the development of a communications network as well as the necessary internal system upgrades required to the MDM and Billing systems. The residential single phase "Bridge" meters are more than double the cost of the traditional AMR meter. Our research shows NU can purchase a residential AMR meter for about $38, while the residential "Bridge" meter would be approximately $81 per meter. This additional cost however, is not offset by any additional short-term savings. The Company does not know if it would ever convert to AMI, or that when it did convert, the best communication technology at that time would be able to interface with these "Bridge" meters. Additionally, this option would commit PSNH to a single meter manufacturer for the foreseeable future. The "Bridge" meter option simply positions the Company to someday convert to AMI, but in the meantime, the additional $20 million cost for these meters provides no additional benefits to PSNH or its customers.

The third option examined was to install a full AMI system with all of the features available including outage notification, restoration notification, remote disconnect and reconnect capability, the ability to send pricing signals to the meter to reduce load during peak pricing periods, as well as hourly reads for off-peak pricing options, etc. This option is by far the most expensive option due to not only the higher cost of the AMI meters, but also the design, development and deployment of a sophisticated communications network, as well as associated required upgrades to the billing system, MDM, OMS and other system interfaces. The group's research has found that most of the US utilities who have moved into the AMI space have done so either to satisfy regulatory mandates (such as in California and Texas) or because the companies received federal stimulus money (Smart Grid Investment Grants), dramatically reducing the company's share of AMI costs (such as Central Maine Power and the NH Electric Cooperative locally). Additionally, customer opposition to AMI meters is spreading in some areas of the country such as Maine and California, and there is a lack of interest among customers to participate in off peak pricing programs. Furthermore, in deregulated markets such as NH, the Suppliers have not typically offered Off Peak Pricing or Critical Peak Pricing options in their portfolios, so the hourly usage data available from AMI meters would typically not be utilized for customers served by alternate suppliers. Finally, in NH, legislation passed in June 2012 requires that utilities that install "Smart Meters" must obtain the customer's permission before installing that meter on the home or business. This would be a significant administrative burden to PSNH, and creates an "Opt In" process for AMI. This would significantly reduce the benefits of AMI in NH as the communications network would still be needed and the internal IT costs would still be incurred, but not all customers would participate. For all of these reasons, an AMI solution was not recommended for PSNH.

Below is a table of the estimated costs and savings associated with the 3 options that were analyzed:

PSNH Automated Meter Reading: Capital Cost/Benefit Summary ($000's)			
	AMR	**"Bridge"**	**AMI**
Capital Costs			
Meter Installed Costs[1]	$37,522	$57,314	$87,796
Communications Equipment	$540	$540	$25,000
Information Technology	$2,875	$2,875	$25,000
Totals	**$40,937**	**$60,729**	**$137,796**
Benefits			
Avg Annual Savings[2]	$6,700	$6,700	$10,250
Total FTEs Reduced	57	57	86

1. Includes costs for acceptence testing and scrap value benefit
2. Avg annual savings over a 20 year evaluation period

The estimate of $25M for communications costs for an AMI project in PSNH's territory are based upon data provided to the US Department of Energy by several utilities that received Smart Grid Investment Grants. The data indicates that the Communications costs per customer range from $44 per customer at Central Maine Power to $101 per customer at the NH Electric Cooperative. Using a conservative figure of $50 per customer for the communications costs for PSNH's 500,000 customers results in the $25M estimate. PSNH did not pursue a more detailed estimate of the AMI costs based upon the limited incremental savings the Company would see from AMI compared to the huge additional investment that would be required compared to AMR. AMI would cost PSNH an additional $97 million, but would save only an additional $3.5 million per year over the 20 year evaluation period.

I hope that this information is sufficient to explain why PSNH and NU reached the decision to install AMR meters. The Company believes strongly that the AMR solution is the prudent and cost justified solution to move away from manual meter reading in NH. I welcome the opportunity to discuss this with you further should you or other members of the PUC Staff wish to do so.

Sincerely,

Daniel S. Comer

Daniel S. Comer
Director – Meter Reading and Field Operations

Cc: Steven Mullen – NHPUC
Amanda Noonan – NHPUC
Allen Desbien - PSNH

STATE OF NEW HAMPSHIRE

Inter-Department Communication

DATE: 20 September 2013
AT (OFFICE): NHPUC

TF

FROM: Tom Frantz – Director, Electric Division

SUBJECT: DE 13-215; Petition by Public Service Company of New Hampshire to Waive Puc 305.03, Test Schedules for Watt-hour Meters and Demand Devices

TO: Chair Ignatius and Commissioners Harrington and Scott
Executive Director Howland

On July 17, 2013, Public Service Company of New Hampshire (PSNH) filed a petition pursuant to the New Hampshire Code of Administrative Rules Puc 201.05, seeking a waiver of specific aspects of the Commission's requirements relative to test schedules for watt-hour meters and demand devices under Puc 305.03.

For support of its waiver, PSNH cites Puc 201.05 which states that the Commission shall waive the provisions of any of its rules, except where precluded by statute, upon request by an interested party, or on its own motion, if the commission finds that the waiver serves the public interest and will not disrupt the orderly and efficient resolution of mattes before it.

As part of a transition to Automated Meter Reading (AMR) in its service territory, PSNH has begun a meter change out over the next three years that encompasses approximately 540,000 customer meters. The existing meters will be replaced with new AMR meters. The new meters are tested and calibrated before going into the field by the manufacturer. After installation, the new meters will be sample tested in accordance with Puc 305.02, Test and Calibration of Meters. Due to the significant undertaking of the AMR program, PSNH is requesting that the test schedules in Puc 305.03 be waived during the transition period. PSNH states that it be permitted to resume regular meter testing pursuant to Puc 305.03 in October of the year following completion of the AMR installations. PSNH further states that granting the waiver will not disrupt the orderly and efficient resolution of matters before the Commission as the purpose Puc 305.03 is to ensure that the Company inspects and tests meters on a regular basis and remove or repair those meters found deficient. PSNH believes that following the normal testing schedule while it replaces 540,000 customer meters over the next three years would be an inefficient use of its resources and create implementation issues for the AMR program.

Staff agrees that it would be burdensome and an inefficient use of resources to continue testing the existing meters in accordance with Puc 305.03 during the change out of the meters and Staff recommends that the Commission grant PSNH's waiver petition. That said, Staff does have some concerns about the AMR program. Those concerns were expressed at a meeting Staff had with PSNH before the filing was made and are contained in a letter I sent to the Company on July 24 which I have attached to this memo. PSNH responded to Staff's concerns in a letter dated August 15. I have also attached PSNH's response to this memo.

The PSNH response provides much more detail concerning the analysis and cost effects of the three different metering options it evaluated. According to PSNH, it chose the least costly option and the one that it believes makes the most sense when balancing the costs with the benefits of the three options. Staff understands PSNH's position, but doesn't necessarily agree with it though we do agree with PSNH that the recently passed legislation concerning smart meters that creates an "opt in" provision for smart metering will decrease the overall benefit of smart metering and result, ultimately, in a more costly program. These types of managerial decisions are the province of the utility, but Staff believes the burden of its decision resides with PSNH when and if it seeks to recover these costs from customers.

Staff notes that the OCA filed a petition of participation in this proceeding on August 27. It is Staff's understanding that OCA will file comments on the PSNH waiver request.

Please contact me or Amanda Noonan if you have any questions or would like to discuss this matter.

CHAIRMAN
Amy L. Ignatius

COMMISSIONERS
Michael D. Harrington
Robert R. Scott

EXECUTIVE DIRECTOR
Debra A. Howland

THE STATE OF NEW HAMPSHIRE

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July 24, 2013

Dan Comer
Director – Meter Reading and Field Operations
Northeast Utilities Service Company
c/o PSNH
P.O. Box 330
Manchester, NH 03105-0330

Dear Mr. Comer,

Staff appreciated the opportunity to meet with you and your team on July 17 to discuss issues related to PSNH's metering plans. You requested our position on several metering issues, including a waiver of the PUC's 300 rules that address meter sampling, specifically Puc 305.03, Test Schedules for Watt-hour Meters and Demand Devices, and the intention to move from a 30-minute block demand charge calculation to a rolling 30-minute demand charge calculation for applicable demand-metered Rate G customers. You also requested our opinion on your plans to remotely disconnect and reconnect service using the new meters. Staff will first address your specific issues before making some general observations concerning your change out in meters.

Staff supports your interest in waiving the testing requirements of Puc 305.03 during the change out period. It would be inefficient to spend resources complying with the sample requirements of Puc 305.03 when you expect to change approximately 1,000 meters per day. We do, however, expect that PSNH will test the new meters in accordance with all applicable Puc 305 rules and that all customer complaints regarding meter accuracy will be addressed on a timely basis. When the change over to the new meters is completed, estimated to occur sometime in the first quarter of 2016, we expect you will resume periodic testing in accordance with the rules.

Staff also supports the movement to a rolling demand calculation so long as it remains at the 30-minute interval currently in effect. We agree that no tariff change is needed. to implement the new demand billing calculation.

Regarding the capability to remotely disconnect and reconnect electrical service which will result from PSNH's AMR project, Staff would not object to remote service disconnection and reconnections as described further below. Ideally, two processes would be implemented – remote disconnections and reconnections from a central location for customer requested turn on and turn off orders and curbside disconnections for collection related disconnections. Based on the discussion at our meeting on July 17, Staff understands that, absent AMI technology, PSNH cannot implement two different methodologies for remote disconnection. Instead, it must select one method for all customers. In light of that, Staff would support the curbside method for remote service disconnections and reconnections to allow for the collection calls at the door prior to any service being disconnected.

While we have addressed your specific issues associated with your move to AMR, we must state that we have concerns about it. We only yesterday received the benefit-cost analysis and we have not reviewed it, yet, though we intend to do so in the near future. We have not seen any information about the ability of PSNH to integrate these new meters into the various PSNH/NU systems, especially a new outage management system. Technology can play an important role in reducing customer outage time, so your choice of meters and their capabilities or limitations will have effects beyond meter reading, shut-offs and reconnects. Their effect on public safety should be considered. You also mentioned that there are some "wire-line" technological improvements that the company could make now that could improve outage response and reliability. We believe there is no reason not to make those improvements now; they are not dependent upon metering and if they improve outage response at a reasonable cost, Staff supports their deployment.

Finally, you stated that it is "a corporate decision" to not move to AMI. We are concerned that the AMR system may not be upgradable and will not be able to "adapt" to future changes and the potential benefits of a "smarter grid." Those risks will be on the company when it seeks to recover the costs of the new meters.

Again, Staff appreciated the ability to meet with you to discuss your metering plans. We look forward to continued discussions with the Company about changes that can improve customer service, reliability and outage response.

Sincerely,

Thomas C. Frantz

Thomas C. Frantz
Director – Electric Division
New Hampshire Public Utilities Commission

Public Service of New Hampshire d/b/a Eversource Energy
Docket No. DE 19-057

Date Request Received: 08/13/2019 **Date of Response: 09/03/2019**
Request No. OCA 6-085 **Page 1 of 2**
Request from: Office of Consumer Advocate

Witness: Penelope Conner

Request:
Reference New Hampshire Grid Modernization Report Appendix, Page 40, Table B12.c, describing Eversource as having deployed 527,445 AMR meters between 2014 and 2015, and Connecticut Public Utility Regulatory Docket No. 17-12-03, Investigation into Distribution System Planning of the Electric Distribution Companies, Eversource Metering and Billing – PURA Technical Meeting 8.17.18.ppx, slide 5-6, showing a transition to AMR bridge meters in 2016. Please describe why the year following completion of its deployment of AMR meters in New Hampshire the Company transitioned to AMR bridge meters in Connecticut.

Response:
Eversource Energy has not undertaken a system-wide initiative to "transition" from AMR meters to AMR/AMI bridge meters in Connecticut. In fact, the first AMR/AMI bridge meters installed on the Eversource Energy system were installed in New Hampshire during the AMR conversion project in order to support “curb side” remote disconnect and reconnect in unsafe or hard-to-access locations. AMR/AMI bridge meters have two capabilities that AMR meters do not have, which are: (1) the capability to enable remote or "curbside" disconnects in unsafe or hard-to-access locations; and (2) the capability to enable two-way communications in the event that an AMI system is implemented (including all communications and systems infrastructure needed for implementation).

Although AMR/AMI bridge meters are capable of two-way communication, the basis for Eversource Energy's use of these meters is the remote disconnect capability. To enable the two-way communication function, and a full-scale AMI system must be implemented including all communications and information systems support. In addition, the AMI capability may be utilized only if AMI is implemented using the same vendor/manufacturer as the AMR/AMI bridge meter. In that regard, Eversource Energy is currently purchasing AMR/AMI bridge meters from Itron; however, it is unknown whether Itron would be the best vendor/manufacturer for a future AMI system given that there is no plan, design or project as yet under development for AMI implementation. Please see the Company's response to STAFF 10-003 for a discussion of the challenges with AMI implementation.

In 2016, Eversource Energy began to install AMR/AMI bridge meters in unsafe or hard to access locations in Connecticut and Massachusetts, leveraging the experience gained in New Hampshire with the advantages of remote disconnect capability. CL&P's AMR system is mature, having been installed in the early 2000's, and is nearing the end of its useful life. Therefore, CL&P is installing AMR/AMI bridge meters in unsafe, hard-to-access locations and is using these meters as the replacement meter technology for aging AMR equipment. NSTAR Electric Company is following the same strategy of using AMR/AMI meters in hard-to-access locations and as replacements for old AMR equipment, given that its

AMR system is also relatively mature. Within both the CL&P and NSTAR Electric service territories, hundreds of thousands of AMR meters will not be replaced with bridge meters for many years because the meters are not nearing the end of their useful life and/or are not hard to access. These AMR meters will be replaced only if Eversource decides to implement AMI.

Lastly, PSNH is continuing to install AMR/AMI bridge meters in hard-to-access locations and as replacements for meters that are replaced for condition or other reasons.

The current installation of AMR versus AMR/AMI bridge meters for the Eversource Energy electric operating affiliates is as follows:

Operating Company	AMR/AMI Bridge Meters	Non-Bridge AMR
CT	211,726	1,063,993
MA (East)	163,300	1,032,172
NH	43,029	532,155
MA (West)	24,998	193,736
Total	443,053	2,822,056

Public Service of New Hampshire d/b/a Eversource Energy
Docket No. DE 19-057

Date Request Received: 08/13/2019 **Date of Response: 09/03/2019**
Request No. OCA 6-082 **Page 1 of 1**
Request from: Office of Consumer Advocate

Witness: Penelope Conner

Request:
Reference McLean Conner Testimony, Bates 781, Lines 12-15, stating "To inform the decision, the Company developed a comprehensive business case analysis, considering the costs and benefits, as well as qualitative factors, associated with the available technologies."

a. Please provide the comprehensive business case analysis the company developed.
b. Please explain whether the Company's business case included the demand reduction dollar benefits associated with opportunities for an opt-in time of use rate offering or an opt-out peak time rebate offering, and why.

Response:

a. Please see the response to TS-011 and STAFF 10-010 for the requested materials.
b. Please see the Company's response to STAFF 10-003 for a discussion relating to this point. Performing this type of analysis would have required extensive assumptions about customer performance during curtailments in addition to assumptions about the ability to effectively reduce monthly and annual peak system loads. As a result, the analysis would not have provided reasonably reliable data to use in the business case analysis.

Public Service of New Hampshire d/b/a Eversource Energy
Docket No. DE 19-057

Date Request Received: 10/25/2019 **Date of Response: 11/14/2019**
Request No. OCA TS 1-007 **Page 1 of 1**
Request from: Office of Consumer Advocate

Witness: Penelope Conner

Request:
Refer to Eversource's response to Staff 10-003, pages 5 and 6, which indicates that only 38% of Northeast Utilities' customers had central air conditioning in 2012, that only 4,000 of these customers had sufficiency discretionary load to shift for time-varying rates, and that the benefits to participating customers would only be $161 per year, "based on research performed in 2012". a. Provide a copy of the research conducted in 2012 to which this statement refers. b. Provide calculation details indicating how the benefits to participating customers would only be $161 per year. Provide all workpapers showing how this benefit estimate was derived. c. Provide any research Northeast Utilities has conducted as to the system-wide economic benefits associated with the use of time-varying rates in its service areas.

Response:

a) The statements are consistent with the key findings of the Final Technical Report for the NSTAR Smart Grid pilot included as Attachment OCA TS 1-007 A. The 24-month pilot conducted by NSTAR Electric Company and the associated evaluation by Navigant Consulting demonstrated that only a narrow segment of the population is likely to participate or contribute to savings through time-varying rates, that the residential sector is a limited source of reducing peak load costs and that savings will come from larger customers with discretionary loads.

b) Please refer to Attachment OCA TS 1-007 B for analysis that was prepared to evaluate the potential savings under a time-varying rate structure for NSTAR Electric Company.

c) Eversource and it's affiliates have completed or contributed to several analyses to assess potential customer response and the associated costs and benefits of time-varying rates but have not conducted studies or analysis that included system-wide economic benefits within the scope. The Company anticipates that system-wide economic benefits associated with the use of time-varying rates would be constrained by the same factors that limit anticipated electric system benefits as explained in part a. of this response - that only a narrow segment of the population is likely to contribute to savings through time-varying rates.

Evaluation Methods

The data collection and analysis approach was developed to meet the needs and regulatory requirements of both process and impact evaluation. Because of the technology demonstration goals, data collection was enhanced to include information to help understand the performance, reliability, and effectiveness of the Smart Grid technology. Thus, data collection was intended to meet the needs of multiple constituencies, including the DOE, the Massachusetts Department of Public Utilities, and NSTAR itself.

To meet these diverse needs, data collection consisted of three different data sources:

1. Interval meter data provided by the pilot technology along with demographic, weather, and other data needed to perform a statistically significant impact evaluation
2. Survey data collected from participants at various points in time throughout the pilot and addressing a variety of topic areas including use and acceptance of the technology, experience with installation, and overall views toward the program
3. Technology data generated by, or developed to track the performance of, various elements of the technology platform to help better assess the performance of the technology itself

The estimation of the consumption impacts of all four test groups used hourly and/or monthly meter data collected for each participant as well as for the control group. The evaluation treated all of the individual time series as a single panel (or longitudinal) data set; that is, a data set that is both cross-sectional (including many different individuals) and time series (repeated observations for each individual). The consumption impacts of all four groups were then estimated using fixed-effects regression analysis with weather normalization.

Energy and Peak Demand Savings Impacts

The purpose of the impact analysis was to quantify changes in energy consumption and peak period demand resulting from participation in each of the four test-group components of the pilot program. Based on participant consumption data from January 2012 through December 2013, major findings of the impact analysis include the following:

- Peak period load impacts. Customers on the TOU/CPP rates (Groups 3 and 4) reduced summer peak period loads by approximately 0.2 kilowatts (kW), or about 15% of their average peak period load. Customers on the standard rate also reduced their load during peak hours, but only by approximately half as much as customers on the TOU rate.
- Impacts of critical events. Customers with automated load control of central air conditioning (Groups 2 and 3) reduced demand by approximately 0.5 kW during events (roughly 20-25%). Customers on the TOU/CPP rate without automated load control reduced consumption by an average of 0.13 kW (9%) during events.
- Annual energy impacts. Customers on the TOU/CPP rates reduced their annual energy consumption by approximately 2%, while customers on the standard rates did not show a statistically significant change in consumption. The weather-normalized analysis shows that savings have *decreased* as the pilot progressed, with summer 2012 savings exceeding summer 2013 savings (roughly 2% savings vs. no savings across all participants) and changes in winter consumption moving from a moderate decrease during the first winter (roughly 3%) to a similar increase in the last three months of 2013.
- Persistency. The analysis shows that savings have decreased as the pilot progressed, with summer 2012 savings exceeding summer 2013 savings (roughly 2% savings vs. no savings across all participants) and changes in winter consumption moving from a moderate decrease during the first winter (roughly 3%) to a similar increase in the last three months of 2013.