STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

In the matter of

Docket No. **DE 19-057**

REQUEST FOR PERMANENT RATES

DIRECT TESTIMONY

OF

PAUL J. ALVAREZ

ON BEHALF OF

THE OFFICE OF THE CONSUMER ADVOCATE

December 20, 2019

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I. INTRODUCTIONS

Q. Mr. Alvarez, would you please state your name, business address, and occupation?

A. My name is Paul J. Alvarez. My business address is Post Office Box 620756, Littleton, Colorado 80162. I am president of The Wired Group, a consultancy dedicated to maximizing the value of utility distribution grids and businesses to customers.

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

A. I am testifying on behalf of the Office of Consumer Advocate (OCA) in this case.

Q. Please describe your formal education and professional experience.

A. I received a bachelor's degree in business administration from the Kelley School of Business at Indiana University in 1984 and a master of management degree from the Kellogg School of Management at Northwestern University in 1991. After 15 years in Fortune 500 product development and product management, I entered the utility industry in 2001 with responsibilities that focused on demand-side management and renewable energy program development and rate design, marketing, and impact measurement. These experiences led to two unique projects involving the measurement of grid modernization costs and benefits, which revealed the limitations of current utility

regulatory and governance models.[1,2] I formed the Wired Group in 2012 to focus exclusively on consumer and business advocates' need for expertise in grid modernization and utility performance measurement. I have since testified in, or served as consultant to clients in 18 states in support of cases before utility regulatory commissions regarding distribution (including meters) planning, investment, and performance measurement.

I am the author of *Smart Grid Hype & Reality: A Systems Approach to Maximizing Customer Return on Utility Investment*, a book originally published in 2014 and revised for its second edition published in 2018. I am also the developer of the Utility Evaluator, an Internet-based application which benchmarks investor-owned utility performance on 30 different financial and operating metrics from publicly-available data (FERC Form 1, EIA Form 861, JD Power and Associates, state regulatory filings, etc.).

Q. Have you previously testified before this Commission?

A. I submitted Comments on September 6, 2019 jointly with my associate, Dennis Stephens, in IR 15-296 regarding distribution planning process recommendations. My full Curriculum Vitae, which briefly describes all appearances before U.S. state utility regulators, is provided as Appendix A to this testimony.

[1] Colorado PUC 11A-1001E. *SmartGridCity Project Evaluation Summary*. Exh. MGL-1. Dec. 14, 2011.

[2] Ohio PUC 10-2326-GE-RDR. *Duke Energy Smart Grid Audit and Assessment*. June 30, 2011

Q. What is the purpose of your testimony?

A. The OCA has engaged me to review PSNH's investment in traditional meters equipped with automated meter reading (AMR) technology, for which PSNH is requesting a return of and on costs in this case.

Q. Please preview your testimony.

A. I believe PSNH's investment in traditional meters equipped with AMR technology, to have been imprudent, and that cost recovery should therefore be denied. My testimony is organized as follows:

- PSNH has not demonstrated that meter replacement was necessary.
- While the meters PSNH installed eliminated manual meter reading, the technology deployed was not the least cost means to do so.
- If PSNH were to replace its meters, it should have used industry standard technology (advanced metering infrastructure) offering interval usage data.
- PSNH's decision to replace meters with non-standard technology was biased and calculated to forestall interval usage data availability.
- PSNH's decision to replace meters with non-standard technology harmed customers and markets in defiance of New Hampshire law and policy.

II. PSNH HAS NOT DEMONSTRATED THAT METER REPLACEMENT WAS NECESSARY

Q. When did PSNH replace its meters with those for which it is requesting cost recovery in this Case?

A. PSNH replaced its meters in 2013.[3]

Q. Why did PSNH replace its meters?

A. PSNH justifies replacing its meters through the cost savings associated with the elimination of the physical meter reading operations in existence at the time.[4] In discovery, PSNH described additional benefits associated with the elimination of physical meter reading operations, including improvements in employee safety and reductions in estimated and errant meter readings.[5] However, PSNH did not estimate any economic benefits from these features. PSNH provided no evidence that employee safety incidents, or estimated and errant meter readings, were on the rise,[6] or that they constituted priority problems necessitating replacement of existing meters.

[3] Direct testimony of Penelope McClean Connor at 47 (Bates 000785), line 7.
[4] Schedule PJA-1.
[5] Schedule PJA-2.
[6] Schedule PJA-3.

Q. Did PSNH provide any evidence that its meters required replacement?

A. Not in direct testimony. In discovery, PSNH added that its meters were aging, but described no customer consequences associated with this fact. PSNH also noted in discovery that hand-held meter reading devices used by meter readers to record meter data, which at the time numbered 100, were failing and no longer being supported by available meter data collection software.[7] However, PSNH provided no hand-held meter reading device failure rates, nor described any consequences associated with a lack of software support. Additionally, to the best of my recollection, 100 new handheld devices and software could have been had for only about $100,000 in 2013.

Q. In your opinion, could PSNH have continued to provide adequate service using the electric meters and metering systems in place in 2012?

A. Yes.

[7] Schedule PJA-2.

III. WHILE THE METERS PSNH INSTALLED ELIMINATED MANUAL METER READING, THE TECHNOLOGY DEPLOYED WAS NOT LEAST COST

Q. To summarize, PSNH claims it replaced its electric meters to secure the benefits associated with the elimination of physical meter reading operations, correct?

A. Correct.

Q. **What options did PSNH evaluate in the pursuit of physical meter reading operations elimination?**

A. PSNH evaluated three options to eliminate physical meter reading operations. These included replacing the electric meters with 1) traditional meters featuring automated meter reading (AMR) functionality; 2) "Bridge" meters, which function as AMR meters but are upgradable to advanced metering infrastructure (AMI); and 3) a full AMI metering system (including a two-way wireless communications system).

Q. How did PSNH justify the selection of AMR meters?

A. PSNH justified the selection of AMR meters as the lowest-cost method to eliminate physical meter reading operations.

Q. Was the replacement of existing electric meters with AMR meters the lowest-cost method to eliminate physical meter reading operations?

A. No. If PSNH's primary goal was to eliminate meter reading operations, the least cost way to do so in 2013 would have been to add radio modules to the existing meters. These modules allow meters to be read by vehicles which drive through neighborhoods in exactly the same manner as the AMR meters PSNH installed, collecting data from thousands of meters per vehicle per day, but without the cost of replacing the entire electric meter. The radio modules are retrofitted to existing meters, and typically consist of a round transistor board which fits under the meter glass. Though they have fallen out of favor today, in 2013 there were likely millions of mechanical meters retrofitted with AMR in service in the US. Retrofit options were offered by major manufacturers like Sensus and Itron. In fact, in Connecticut and Massachusetts, PSNH affiliates use Itron's Field Service Collection System, a drive-by system using AMR modules in a variety of meters.[8] Given that the company has several types of mechanical meters still in service in

[8] Schedule PJA-4.

those states,[9] it is likely at least some of those meters were retrofitted with AMR modules in exactly the manner I describe.

Q. Did PSNH evaluate the drive-by meter retrofit option?

A. No.[10]

Q. Did PSNH explain why not?

A. PSNH explained that the cost of the new meters, at about $33, was likely not much more than the cost of retrofitting traditional meters with the drive-by radio option.[11] In addition, PSNH claimed that the drive-by retrofits are not a substitute for meter replacement,[12] inferring that the two options weren't comparable.

Q. Do you concur with these assessments?

A. No. The total cost of the AMR meters PSNH chose to install was $70.55 per meter,[13] not $33. By comparison, including installation, the cost of retrofitting a drive-by

[9] *Id.*
[10] Schedule PJA-2 (a).
[11] *Id.*, (c).
[12] *Id.*, (b) and (d).
[13] Schedule PJA-1. Attachment Q-TS011A. Page 4, column "AMR", line "Average Installed Cost Per Meter."

system in 565,000 existing meters would probably have been less than $20 per meter. The cost of associated IT systems, $3.3 million,[14] as well as vehicle equipment, would have been the same under either full meter replacement or retrofit scenarios for drive-by meter reading. Finally, since PSNH provided no rationale for meter replacement, any claim that drive-by retrofits are not a substitute for meter replacement is irrelevant. Either replacing old meters with AMR-equipped meters, or retrofitting meters with AMR modules, delivers the same result: the elimination of physical meter reading operations. PSNH should have evaluated the benefits and costs of all potential options available for eliminating physical meter reading, and selected the option offering the greatest benefits for the least cost.

Q. To clarify, your testimony is that PSNH changed out its entire installed base of meters to eliminate physical meter reading operations, even though it could have simply retrofitted those meters at a much lower cost. You also testify that PSNH did this despite the fact that PSNH is likely to have retrofitted old meters with AMR in Connecticut and Massachusetts. Is that correct?

A. Yes, that's correct.

[14] Schedule PJA-6. P. 2.

Q. Do you have any theories as to why PSNH would have done this?

A. Of course, I can only hypothesize as to why PSNH would have replaced electric meters to automate meter reading, when it could have simply retrofitted those meters. But, I do have some theories. One theory is that PSNH was interested in growing its rate base, motivated by capital bias as all investor-owned utilities are. Another theory is that PSNH intentionally installed meters without the interval data capabilities required to offer time-varying rates. This theory maintains that one of PSNH's goals was to delay the onset of time-varying rates by installing new meters which could not offer the interval usage data required to bill such rates. I will provide support for this theory in the balance of my testimony.

IV. IF METERS WERE TO BE REPLACED, PSNH SHOULD HAVE USED INDUSTRY STANDARD TECHNOLOGY (AMI) OFFERING INTERVAL USAGE DATA

Q. How long have you been in your current line of work?

A. As indicated in the Introduction and Appendix A (my Curriculum Vitae) to this testimony, I have been evaluating grid modernization plans, investments, and results, including advanced metering infrastructure (AMI) deployments, since 2010.

Q. So, utilities have been deploying AMI since before 2010?

A. Yes. In 2008, AMI deployments accelerated rapidly as a result of the American Reinvestment and Recovery Act (ARRA), enacted by Congress to stimulate the economy during the Great Recession. The Smart Grid Investment Grant program (SGIG, part of ARRA) offered utilities $4 billion in matching grants, and was designed to get utilities to invest a lot in their grids extremely quickly. As AMI deployments are quick to plan compared to other electric distribution technologies, a large amount of utility applications for SGIG matching grants featured AMI. In just a few years the SGIG prompted the installation of over 10 million AMI meters, and they quickly became the industry standard for new meters. Before the SGIG programs, electric utilities typically replaced old meters with new ones on a premise-by-premise basis, and only when individual meters which failed were deemed beyond repair. Utilities largely began "en masse" (all at once) replacements of old meters with AMI meters coincident with the SGIG. To my knowledge, all "en masse" meter replacements since 2010 have featured AMI meters. By July 2013, when PSNH installed traditional meters equipped with AMR, the Edison Foundation estimated that 46 million AMI meters had already been installed in the US.[15]

[15] Cooper A., *Electric Company Smart Meter Deployments: Foundation for a Smart Grid*. Institute for Electric Innovation, Edison Foundation. October, 2016. Figure 1, page 2.

Q. Since 2010, other than PSNH, do you know of any utility which has completed an "en masse" replacement of all old meters with new meters which were not AMI meters?

A. No.

Q. What are the advantages of AMI meters over the traditional type PSNH installed?

A. In my experience, the advantages of AMI meters are highly variable, and depend to an almost exclusive degree on how a utility chooses to employ them. I have seen investor-owned utilities minimize AMI capabilities which cause them economic harm under the current ratemaking model, including time-of-use rate capabilities designed to reduce peak demand (due to utility capital bias) and grid and customer efficiency capabilities (due to the utility throughput incentive). In primary and secondary research I've led, I've found demand reduction and energy conservation potential to represent between 35 and 50 percent of the total economic benefits utilities could deliver to customers from AMI, with most of the rest coming from the elimination of physical meter reading operations, revenue assurance, and outage restoration, in rough order of magnitude.

Q. What is it about AMI meters which provides large demand reduction and energy conservation potential?

A. AMI meters record both the amount and the timing of customer energy use. Utilities set the timing parameters, called intervals, used to track energy use over time. Must utilities set timing parameters in blocks of 5, 10, or 15 minutes. Knowledge of usage with this level of granularity relative to time can help educate consumers, as it helps them equate the use of certain loads (air conditioning, clothes dryers, etc.) to time-based energy records. Interval usage data can also enhance conservation through usage alerts, which notify consumers of high usage throughout a month, rather than having to wait for the receipt of a bill after the month is over.

Interval data can also be used to bill time-of-use rates designed to reduce coincident system peak demand. Once usage is associated with time intervals, electricity can be priced differently for different times. By offering rebates to customers who conserve during system peaks, for example, system peaks can be reduced. In Maryland, all electricity customers billed under the standard service offer have an opportunity to earn such rebates with no sign-ups required.

Interval data has been put to other good uses in retail choice markets like New Hampshire's. In Texas, ERCOT requires energy charges to each retail energy supplier to be settled by hour, based on market prices and the aggregated actual usage of all individual customers the competitive energy retailer serves. As one might imagine, holding each retailer economically responsible for its customers' use of energy during high-priced times has spurred lots of innovations. Retail

energy suppliers in Texas offer rate discounts for installing controllable thermostats, real-time pricing, and other innovations. In Ohio, regulators have established a policy that not only energy costs, but also capacity costs, be settled for retail energy suppliers (and, presumably, community choice aggregators) based on customer-specific interval usage data measured by AMI meters.[16] (ERCOT does not have a capacity market.)

Q. Can the AMR meters PSNH installed record energy usage by interval?

A. No.[17]

Q. So, until the AMR meters are replaced, no PSNH customer will be able to take advantage of interval data capabilities, energy conservation features, demand response rebates, or other market innovations such as those available in Maryland, Texas, or Ohio?

A. That is correct, and more than just unfortunate. Since 1996, New Hampshire state laws and policy, as well as rules and policies established by this Commission, have declared that electricity should be subject to market forces to as great an extent as possible. Through its failure to adopt industry standard AMI technology, PSNH

[16] *PowerForward: A Roadmap to Ohio's Energy Future.* Public Utilities Commission of Ohio. P. 32.
[17] Schedule PJA-7.

has effectively denied market innovation and animation in New Hampshire in clear and direct defiance of state law and policy. I will return to the subject of New Hampshire state law and policy related to energy later in this testimony.

Q. Is it your belief that PSNH intentionally installed meters which could not bill time-of-use rates to forestall such innovations?

A. Yes, and I offer two sets of direct evidence in support of this belief, as well as circumstantial evidence I'll describe in the next section of testimony. The first set of direct evidence which indicates PSNH used its metering technology choice to forestall innovations related to interval usage data is found in PSNH's 2013 Least Cost Integrated Resource Plan (LCIRP) proceeding. In a technical session on January 27, 2014, Russell Johnson, PSNH's Manager of System Planning and Strategy at the time, stated that meters were not part of the (LCIRP) planning process. OCA witness James Brennan testimony in that case cites the statement,[18] which was not challenged by PSNH in discovery or in hearings. PSNH attorney Matthew J. Fossum confirmed PSNH's intention to divorce distribution investment choices, like meters, from resource planning, stating at hearing: "I would want to make clear that PSNH's distribution and transmission planning is planning for distribution and transmission. It is not planning based on its

[18] NH OCA DE 13-177. Direct testimony of James Brennan. February 21, 2014. Page 14 at 1.

generation needs."[19] From this statement it is clear PSNH had no interest in using standard AMI meter capabilities to manage customer energy use or demand. In other words, PSNH made its decision about meter investment without regard to how the choice would affect the deployment of bill-reducing innovations – a determination that not only flies in the face of New Hampshire's LCIRP principles[20] but also has profound implications when the question is whether the Company made a prudent investment decision.

The second instance of direct evidence is a letter from PUC Staff (Thomas Frantz) to PSNH (Dan Comer) summarizing a meeting between the two on July 17, 2017. In the letter dated July 24, 2017, Mr. Frantz quoted from the meeting: "[Y]ou (referring to Mr. Comer) stated that it is a 'corporate decision' to not move to AMI."[21] I believe the 'corporate decision' to not move to AMI was motivated by an interest in forestalling market innovations available from interval usage data. I note that the 83 percent of the electric meters PSNH's affiliate installed in Connecticut and 87 percent of the electric meters PSNH's affiliate installed in Massachusetts are also unable to provide interval usage data.[22]

[19] NH PUC DE 13-177. Transcript of Hearings held on April 2, 2014. Page 60 at 21.
[20] As specified in RSA 378:38 and :39, the purpose of PUC review of utility least-cost integrated resource plans is to assess the extent to which the utility's capital deployment decisions are consistent with the state energy policy enshrined in RSA 378:37. Section 37 "declares that it shall be the energy policy of this state to meet the energy needs of the citizens and businesses of the state" – i.e., in the electric context, all of the costs reflected on a customer's electricity bill – "at the lowest reasonable cost" while, *inter alia*, "maximize[ing] the use of cost-effective energy efficiency and other demand side resources."
[21] Schedule PJA-8, at 8.
[22] Schedule PJA-9, unnamed table, at 2.

While this direct evidence appears to make clear that PSNH installed meters in 2013 with the express intention of forestalling market animation and innovations associated with interval usage data available from AMI meters, I will discuss circumstantial evidence in the next section of this testimony.

V. PSNH'S DECISION TO REPLACE METERS WITH OUTDATED TECHNOLOGY WAS BIASED AND CALCULATED TO FORESTALL INTERVAL USAGE DATA AVAILABILITY

Q. Why do you believe PSNH's decision to replace meters with outdated technology which could not provide interval data or bill time-varying rates was biased and calculated?

A. By 2013, when PSNH made the decision to install meters that could not provide interval usage data, it was clear that such data presented several types of economic harm to PSNH. For example, research indicates that the time-varying rates AMI meters make possible can reduce both system peak demand and energy use.[23] PSNH profits increase when the Company invests in the transmission and distribution infrastructure required to satisfy system peak demand, biasing the Company against time-varying rates and peak-time

[23] King C. and Delurey D. *Efficiency and Demand Response: Twins, Siblings, or Cousins?* Public Utilities Fortnightly. March, 2005.

rebate programs. PSNH profits decrease when energy sales volumes fall between rate cases, biasing the Company against the conservation potential offered by AMI meters.

By 2013, there was also evidence from other retail choice markets that AMI meter data was being used successfully by retail energy suppliers to increase their market shares. In Texas, as just one example, retail energy suppliers have used "Free Tuesdays" and "Free Saturdays" offers to grow market share. (Such rates cannot be offered without the interval usage data available from AMI meters.) Retailers in the Houston and Dallas/Fort Worth markets have been offering such rates since AMI meters were first installed by the electric distribution companies serving those markets (CenterPoint and Oncor, respectively) from 2008-2012. It is certainly possible, if not likely, that PSNH felt threatened by retail energy suppliers, and wanted to restrict their opportunities to grow market share at the expense of PSNH market share.

Events since 2013 have only increased PSNH's bias against AMI-related demand response and energy efficiency successes. I note the developments in New Hampshire's Energy Efficiency Resource Standard (EERS) programs as an example. As described in the Commission's Order approving the Settlement Agreement in DE 15-137, New Hampshire utilities can earn incentives, and compensation for lost revenues, based on the level of utilities' EERS program successes.[24] However, when demand response and conservation occur outside of such programs, as would be the case for time-varying rates and programs offered by retail energy suppliers, PSNH has no opportunity to earn incentives or lost revenue compensation.

[24] NH PUC DE 15-137. Order No. 25,932 dated August 2, 2016.

A second example is PSNH's response to Chapter 286 of the 2019 New Hampshire Laws (SB 284), a statute adopted by the General Court at the request of the OCA. SB 284 paves the way for the development of a statewide utility customer data platform, which will use the Green Button "Connect My Data" standard to give every utility customer in New Hampshire the ability to share granular usage data with non-utility providers of innovative energy services that would inevitably chip away at PSNH's business dominance. PSNH has made clear its intent to resist such an innovation, filing comments at the PUC in September stating that "having a single statewide repository for such information seems unnecessary and certainly presents challenges" whereas "having utilities retain the obligation to collect, store, and manage customer data . . . on an individual utility basis would be the better course."[25] At the risk of stating the obvious, the efficacy of such a data platform is reduced to the extent that New Hampshire's largest utility succeeds in perpetuating the absence of the kind of granular usage data that AMI meters produce.

Q. Did PSNH provide justifications for its decision to replace its meters with meters unable to provide the interval usage data required for time-varying rates and other market innovations you describe?

A. Yes, PSNH provides several justifications for replacing its meters with meters unable to provide interval usage data, which I'd like to address in turn. These include 1) that New Hampshire law requiring customer permission for smart meter gateway installation

[25] Joint Utility Comments filed by PSNH in NH PUC IR 15-296 (Investigation into Grid Modernization) on September 9, 2019 at 8.

effectively precluded AMI deployment; 2) that an AMI deployment would not have been cost-effective; and 3) that the communications network required for AMI would be difficult to design and operate given New Hampshire's mountainous topography.

Q. Describe the New Hampshire law requiring customer permission for smart meter gateway installation.

A. SB 266, passed in 2012, requires electric utilities to obtain customer permission before installing any smart meter gateway device. In the law, "smart meter gateway device" is defined as "any electric utility meter . . . which serves as a communications gateway or portal to electrical appliances, electrical equipment, or electrical devices within the end-user's residence or business, or which otherwise communicates with, monitors, or controls such electrical appliances, electrical equipment, or electrical devices".[26]

Q. How does PSNH suggest this law effectively precluded AMI installation?

A. PSNH contends that requiring customer permission to install AMI meters would have resulted in low adoption rates and higher costs. Higher costs would result from the need to maintain two metering systems, one for customers giving approval for gateway devices and one for customers for which such approval could not be obtained. While I agree with this contention in principle, I note that PSNH ignored a much simpler solution which would have allowed PSNH to comply with the law and avoid the requirement to secure

[26] RSA 374:62.I.(a).

customer permission while still deploying AMI meters on a universal basis. The simple solution is to purchase AMI meters without the technology required to communicate with customers' electrical appliances/equipment/devices, thereby making it impossible for such AMI meters to serve as gateway devices. The technology required to turn an AMI meter into a gateway device is offered as an extra-cost option by AMI meter manufactures. PSNH needed only to decline the extra-cost option for the gateway technology, which is generally a communications chip compliant with the ZigBee short-range wireless communications standard, to purchase AMI meters which would have been physically unable to perform the gateway function for which New Hampshire law requires customer permission. PSNH could have easily installed AMI meters without the gateway function to both comply with the law and avoid obtaining customer permission.

Q. Please address PSNH's claim that an AMI deployment would not have delivered benefits in excess of costs.

A. In discovery, PSNH provided cost estimates for the three meter replacement options it considered, as I noted earlier: 1) traditional meters featuring automated meter reading (AMR) functionality; 2) "Bridge" meters, which function as AMR meters but are upgradable to advanced metering infrastructure (AMI); and 3) a full AMI metering system (including a two-way wireless communications system). While the traditional meters featuring AMR functionality fared best in the comparison, an option not considered -- to retrofit existing meters with AMR modules -- would have eliminated physical meter reading operations at a lower cost. As I testified earlier, the absence of a viable option

from PSNH's decision-making process is a critical deficiency when assessing prudency. But there is another critical deficiency in PSNH's decision-making process: PSNH made no attempt to consider the potential benefits of an AMI deployment. For a fully-informed decision, PSNH should have considered the benefits and costs of each meter replacement option, selecting the one which delivered the highest level of customer benefit relative to customer costs. The potential benefits from AMI I described earlier, from demand response and conservation to market innovations likely from enhanced retail energy supplier cost assignment, are nowhere to be found in PSNH's decision-making process.

Q. Did PSNH explain why it failed to consider the potential benefits from AMI in its meter replacement decision?

A. Yes. In discovery, PSNH explained that it failed to consider the potential benefits from AMI for two reasons: 1) that the potential for time-varying rates to deliver value is low, as indicated by a study PSNH conducted in Massachusetts in 2012;[27] and 2) that PSNH would have had to make too many assumptions, making the results of any benefit estimates unreliable.[28]

Q. Do you believe these explanations to have merit?

A. No. In reviewing the 2012 study results, I noted that customers on time-of-use rates with a critical peak price feature reduced average peak period load by 15 percent, whereas

[27] Schedule PJA-2, at 5.
[28] Schedule PJA-10.

customers on the standard rate reduced their load by only half as much.[29] (The fact that both groups' load fell could be due to weather variation, but is beside the point, which is that customers on time-of-use rates do reduce their loads relative to those not on such rates). Customers with automated control of central air conditioning reduced demand by roughly 20-25 percent during critical peak price events.[30] I consider these impacts significant, particularly considering that 38 percent of PSNH's residential customers have central air conditioning.[31] The impacts are certainly large enough to merit quantification in any evaluation of a potential AMI deployment. Regarding the need to make assumptions, I note that this is the case in any benefit estimation exercise. Furthermore, the 2012 study provided information that could have been used to reduce variability in any assumptions PSNH would have made in estimating AMI benefits. Moving forward with a $38 million decision to install meters without industry-standard interval data capabilities, without at least considering the benefits that might have been available from such capabilities, is inexcusable.

Q. Did PSNH provide other evidence indicating that an AMI deployment would not have been cost-effective?

A. Yes. PSNH claims that an AMI deployment in New Hampshire would only be feasible if accompanied by AMI deployments in Connecticut and Massachusetts, citing IT system costs.[32] In its business case, PSNH estimated the IT costs of a "New Hampshire-only"

[29] Schedule PJA-11, at 5.
[30] *Id.*
[31] *Id.* at 7.
[32] Schedule PJA-2, at 5.

AMI deployment to be $25 million.[33] While I agree this is a significant number, it is impossible for PSNH to conclude that a New Hampshire-only AMI deployment would be infeasible if it hasn't quantified, let alone considered, the potential benefits of interval usage data made available by AMI meters. Further, I believe PSNH's claim reinforces my testimony that PSNH should not have replaced its meters at all, particularly with no evidence that such a replacement was needed. If faced with a situation in which a New Hampshire AMI deployment were only feasible when combined with similar deployments in Connecticut and Massachusetts – which PSNH has not proven – the prudent course of action would have been to avoid replacing New Hampshire meters at all, waiting until all three jurisdictions were ready. As I testified earlier, retrofitting AMR modules to existing meters would have delivered the benefits of physical meter reading elimination without replacing the meters at a much lower cost, with the added benefit of increased time available for rendering a more thoughtful decision on AMI meters as conditions in other Eversource jurisdictions developed.

Q. Your testimony appears to indicate that you would have preferred that PSNH had deployed AMI meters. However, your body of work has been consistently critical of utility AMI benefit-cost analyses. Please explain this apparent contradiction.

A. I am not in favor of, or against, AMI meters. I believe each AMI plan or deployment should stand on its own merits as objectively evaluated. I am against bias in AMI meter decisions, either for or against. It is true that, in multiple cases before regulators across

[33] Schedule PJA-1, at 4.

the US, I have argued that AMI deployment plans be rejected, or that AMI cost recovery be denied, due to a lack of demonstrated cost-effectiveness. My testimony generally claims that the benefits of an AMI deployment would be unlikely to deliver (in the case of deployment plans) or did not deliver (in the case of requested cost recovery) benefits to customers in excess of costs to customers. However, my testimony in these cases does not indicate a belief that AMI meters cannot in any circumstances deliver benefits in excess of costs. On the contrary, my public position on AMI has been clear and consistent, in my book, testimony, articles, and public presentations: AMI can deliver benefits in excess of costs in the right circumstances, and with concerted, post-deployment efforts by regulators, utilities, and customers. In every case in which I have recommended against approval of an AMI deployment plan or cost recovery, such recommendations were based on an absence of plans or actions required for AMI meters to deliver the level of customer benefits required to exceed customer costs.

Q. Have you submitted testimony in other jurisdictions in which you've indicated that a utility's AMI benefit-cost analysis was unduly pessimistic?

A. Yes. In a case in Massachusetts, I testified that Eversource's benefit-cost analysis of a full AMI deployment understated benefits and overstated costs,[34] making it unduly pessimistic. Eversource's Massachusetts AMI benefit-cost analysis appears consistent with a pattern of behavior in which Eversource affiliates actively forestalled interval usage data availability and its potential benefits through meter technology choices.

[34] Massachusetts DPU 15-122/123. Direct testimony of Paul Alvarez. March 10, 2017. Pages 10-17.

Q. What is your reaction to PSNH's claim that the development and operation of an AMI meter communications network would be difficult given New Hampshire's mountainous topography?

A. I think topography is a non-issue, for two reasons. First, I am familiar with AMI deployments in other mountainous areas, including the Sierra-Nevada Mountains, the Rocky Mountains, and the Appalachian Mountains. The communications network engineering discipline exists in large part to solve topographical challenges to wireless communications, and it does so very well. Second, there is no requirement for a utility to develop and operate its own communications network to implement AMI. Public networks, such as those available from AT&T and Verizon, are more than adequate to securely and reliably communicate data from meters to utilities, and have been used by non-profit utilities for that purpose for over a decade.

VI. PSNH'S DECISION TO REPLACE METERS WITH NON-STANDARD TECHNOLOGY HARMED CUSTOMERS AND MARKETS IN DEFIANCE OF NEW HAMPSHIRE LAW AND POLICY

Q. Why do you believe PSNH's decision to replace meters with non-standard technology harmed customers and markets in defiance of New Hampshire law and policy?

A. First, PSNH provides no evidence that the meters needed to be replaced. As I've testified, AMR retrofits are available for old meters to eliminate physical meter reading operations (PSNH's stated goal). So PSNH's decision to replace the meters harmed customers through unnecessary increases of rate base and rates. But PSNH added insult to injury by ensuring the new meters were unable to make interval usage data available. If PSNH were to replace its old meters at all, it should have replaced them with industry standard AMI meters offering interval usage data capabilities.

Q. How does the failure to offer interval usage data capabilities constitute a harm to customers?

A. As described in this testimony, interval usage data capabilities can enhance demand reduction and energy conservation capabilities and stimulate market innovations. By increasing the rate base by $38 million for meters which don't offer this potential, PSNH has effectively raised a barrier to such potential for a long time. Any future consideration of AMI will have to contend with a large existing metering asset, which would have to be abandoned to accommodate an AMI installation. Absent specific action by the Commission in the future, customers may one day be paying for two metering assets – those installed in 2013, and new AMI meters. This makes the cost-effectiveness of any future AMI deployment that much harder to achieve, and therefore less likely. Future consideration of AMI will also have to deal with the fact that manual meter reading expenses, which are a critical benefit in most AMI business cases, will

have already been eliminated, and cannot therefore be used to justify AMI costs. To me, any reduction in future flexibility constitutes a harm to customers.

Q. Why do you believe PSNH's decision to replace meters with those which do not have interval usage data capabilities to be in defiance of New Hampshire law and policy?

A. Since at least 1996, New Hampshire has enacted legislation and pursued policies intended to foster vibrant and competitive energy markets. The first line of electric utility restructuring legislation passed in 1996 states: "The most compelling reason to restructure the New Hampshire electric utility industry is to reduce costs for all consumers of electricity by harnessing the power of competitive markets."[35] The legislation cites Part II, Article 83 of the New Hampshire Constitution, which reads in relevant part: "Free and fair competition in the trades and industries is an inherent and essential right of the people and should be protected against all monopolies and conspiracies which tend to hinder or destroy it."[36] Though I am not an attorney, I infer from this that any action a monopoly takes to restrain competition could be interpreted as unlawful.

More recently and specifically, New Hampshire statewide energy plans, from the first one in 2002 to the most recent in 2018, describe the economic and environmental value to New Hampshire citizens of energy conservation and demand response. As I've testified, energy conservation and demand response potential is enhanced through the

[35] RSA 375-F:1.I.
[36] RSA 375-F:1.II.

interval usage data made available by AMI meters. The 2018 State Energy Strategy specifically endorses market innovation, stating: "New Hampshire stakeholders should seek to empower competitive wholesale electricity markets in order to protect New Hampshire energy infrastructure investments, incentivize low-cost energy, and guard against cost-raising policy impacts from neighboring states."[37] I believe PSNH's decision to install meters without industry-standard interval usage data capabilities stifles, rather than empowers, competitive electricity markets and market innovation.

VII. REVIEW AND RECOMMENDATIONS

Q. Please review your testimony.

A. This testimony provides support for several arguments relevant to PSNH's request for a return of and on its 2013 metering investment:

- PSNH has not demonstrated that meter replacement was required.
- While the meters PSNH installed eliminated manual meter reading, the technology deployed to do so was not the least cost available.
- If PSNH were to replace its meters, it should have used industry standard technology (advanced metering infrastructure) offering interval usage data.

[37] Ten-Year State Energy Strategy, Office of Strategic Initiatives (April, 2018) at 23.

- PSNH's decision to replace meters with non-standard technology was biased and calculated to forestall interval usage data availability.
- PSNH's decision to replace meters with non-standard technology harmed customers and markets in defiance of New Hampshire law and policy.

Q. Given this testimony, what are your recommendations to the Commission?

A. I recommend the Commission find that PSNH's investment in meters was imprudent. Further, I recommend the assets be removed from the rate base, and associated reductions to the requested revenue ordered. I believe an imprudence finding is justified due to the fact that meter replacement was 1) unnecessary; 2) not the least costly way to accomplish PSNH's goal (the elimination of physical meter reading operations); and 3) intended to forestall market innovations, harming consumers and defying New Hampshire law and policy. I refer the Commission to the testimony of OCA witness John LeFever for the exact amounts of rate base and revenue reductions associated with my recommendation.

Q. What are the benefits to New Hampshire if the Commission follows your recommendations?

A. In the short term, the State will benefit by avoiding unnecessary rate increases. Rate increases without corresponding value act as a drag on the New Hampshire economy, and are therefore to be discouraged. In the longer term, removing the assets from rate base provides future flexibility to install AMI meters. Without the albatross of a $38

million asset in rate base, the potential cost effectiveness of a future AMI investment will be enhanced, facilitating AMI deployment and the market innovations interval usage data will prompt. Finally, a finding of imprudence will put New Hampshire utilities on notice, serving as a stern communication from this Commission that investments in distribution grids and businesses which do not serve the interests of customers and the public, as stated in New Hampshire law and policy, are not acceptable.

Q. Does this conclude your testimony?

A. Yes, it does.

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
Schedule PJA-10	OCA DR 6-082(b)
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

DE 19-057
Exhibit 27

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:

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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:
  - New Communications Infrastructure to transmit communications from the meter to the Company (data backhaul);
  - A new Meter Data Management System to collect, store and process interval data;
  - A new Meter Asset Systems to store information about all advanced metering assets;
  - A new Customer Information System ("CIS") to calculate and present bills with time varying rates to the customer;
  - Upgrades to ISO-NE and Load Research Systems to interface with internal metering, CIS and ISO-NE processes; and
  - 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.

047

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 **Page 1 of 2**
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

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.