COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

ELECTRONIC JOINT APPLICATION OF LOUISVILLE	)	
GAS AND ELECTRIC COMPANY AND KENTUCKY	)	
UTILITIES COMPANY FOR CERTIFICATES OF PUBLIC	)	Case No. 2018-00005
CONVENIENCE AND NECESSITY FOR FULL	)	
DEPLOYMENT OF ADVANCED METERING SYSTEMS	)	

DIRECT TESTIMONY

OF

PAUL J. ALVAREZ

ON BEHALF OF THE

OFFICE OF THE ATTORNEY GENERAL

Wired Group

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Submitted May 18, 2018

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DIRECT TESTIMONY OF PAUL ALVAREZ

I. INTRODUCTION, QUALIFICATIONS, PURPOSE, AND PREVIEW

Q. Please state your name and business address.

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

Q. What is your occupation?

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

Q. On whose behalf are you submitting testimony?

A. I am testifying on behalf of the Kentucky Office of the Attorney General (AG).

Q. Please describe your work experience and educational background.

A. My career began in 1984 in a series of finance and marketing roles of progressive responsibility for large corporations, including Motorola's Communications Division (now Android/Google), Baxter Healthcare, Searle Pharmaceuticals (now owned by Pfizer), and Option Care (now owned by Walgreens). My combined aptitude for finance and marketing were well suited for innovation and product development, leading to my first job in the utility industry in 2001 with Xcel Energy, one of the largest investor-owned utilities in the U.S.

At Xcel Energy I served as product development manager, overseeing the development of new energy efficiency and demand response programs for residential, commercial, and industrial customers, as well as programs in support of voluntary renewable energy purchases and renewable portfolio standard compliance (including distributed solar incentive program design and metering policies). There I learned the economics of traditional monopoly ratemaking and associated utility economic incentives, as well as the impact of self-generation, energy efficiency, and demand response on utility shareholders and management decisions. I also learned a great deal about utility energy efficiency and demand response program impact measurement & verification (M & V).

I left Xcel Energy to lead the utility practice for sustainability consulting firm MetaVu in 2008. At MetaVu I employed my M & V experience to lead two comprehensive, unbiased evaluations of smart grid deployment performance. To my knowledge these are two of only three comprehensive, unbiased evaluations of smart grid post-deployment performance completed to date. The results of both were part of regulatory proceedings in the public domain and include an evaluation of the SmartGridCity™ deployment in Boulder, Colorado for Xcel Energy in 2010,[1] and an evaluation of Duke

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

Energy's Cincinnati-area deployment for the Ohio Public Utilities Commission in 2011.[2]

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

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

Q. Have you appeared before the Kentucky Public Service Commission previously?

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

A. Yes, I have prepared testimony on behalf of the Attorney General regarding smart meters in two previous instances. The first instance was Duke Energy's Certificate of Public Convenience and Necessity (CPCN) for Smart Meters (Case No. 2016-00152). The second instance was in the most recent LG&E/KU rate case, in which the Companies described a plan to install smart meters (Case Nos. 2016-00370 and 2016-00371). As part of a global settlement, LG&E/KU ultimately withdrew the smart meter proposal from the rate case, resubmitting their proposal for a CPCN in this case.

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

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

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

A. I provide testimony recommending that the Commission reject the Companies' request for a CPCN to install an Advanced Metering System (AMS). This recommendation is based on my informed opinion that the costs of the deployment are virtually certain to exceed the economic benefits to customers. I present several supporting arguments, and my testimony is organized as described immediately below:

- Smart Meters only deliver economic benefits to customers in excess of costs under certain conditions, many of which are not present in the Companies' Application or circumstances;
- Economic benefits of the size projected by the Companies are unlikely to be realized by customers, and several prerequisites to a favorable benefit-cost ratio for customers are not present in the Companies' Application or circumstances.
- The Companies cost estimates are understated, as they do not include carrying costs or the cost of the premature retirement of existing meters which customers will be asked to pay.

II. SMART METERS ONLY DELIVER BENEFITS IN EXCESS OF COSTS UNDER CERTAIN CONDITIONS

Q. Do you believe grid modernization in general, and smart meters specifically, are a bad investment?

A. No, any utility investment in which customer economic benefits exceed customer economic costs is a good investment. Under the right circumstances, with appropriate investments in certain capabilities, and with extensive post-deployment efforts from utilities, regulators, and customers, grid modernization in general, and smart meters specifically, can provide benefits in excess of costs to customers. In these situations, I believe smart meters can be a good investment.

Q. But couldn't your testimony related to grid modernization and smart meters in other jurisdictions be characterized as being opposed to grid investment?

A. No. A review of my testimony in other jurisdictions, as well as my pronouncements at conferences, in articles, and in my book, indicates a variety of perspectives based on specific situations. For example, in my testimony on behalf of the Environmental Defense Fund before the North Carolina Utilities Commission, I recommended Duke Energy's grid modernization plans, which included a smart meter deployment plan, be subject to more significant intervenor scrutiny in a distinct proceeding.[3] In my testimony on behalf of the Massachusetts Attorney General, I recommended the Massachusetts Department of Public Utilities (DPU) address a variety of missing pre-requisites related to smart meter benefit maximization, including capacity market

[3] North Carolina Utilities Commission E-7, Sub 1146. Testimony of Paul J. Alvarez. January 18, 2018.

designs, certain residential customer rate designs and offer methods, and customer data access, before considering National Grid's smart meter deployment plan.[4] In another case before the Massachusetts DPU, my testimony indicates that Eversource's full smart meter deployment benefit-cost analysis was artificially pessimistic.[5] My book serves as another example. Rather than denigrate grid investments in assets like smart meters, my book focuses on how to maximize smart grid benefits such that customer benefits exceed customer costs. To summarize, I believe a review of my pronouncements on smart meters reflects an unbiased perspective which yields different recommendations in different circumstances based on the merits of each situation.

Q. In your experience, what circumstances and conditions are required for the benefit-cost ratio of a smart meter deployment to be favorable to customers?

A. Regarding each of the primary smart meter benefit types described by the Companies in their Application, I have found that several circumstances and conditions are required to secure a favorable benefit-cost ratio for customers. I would like to describe these circumstances and conditions by benefit type as described by the Companies, including 1) operating expense reductions; 2) non-technical revenue loss reductions; and 3) customer energy conservation. In addition, I would like to discuss a smart meter benefit type of significant size, which I believe to be necessary to a favorable customer benefit-cost ratio, which is not currently available based on the Companies' current

[4] Massachusetts DPU 15-120. Testimony of Paul Alvarez on behalf of the Attorney General. March 10, 2017.
[5] Massachusetts DPU 15-122/15-123. Testimony of Paul Alvarez on behalf of the Attorney General. March 10, 2017.

circumstances. That is, the opportunity to avoid or delay investments designed to increase system capacity during coincident system peaks through extensive customer participation in time-varying rates.

Q. Please describe the circumstances and conditions required to maximize operating expense reductions from smart meter deployments.

A. The single most overlooked requirement to securing operating expense reductions for customers from smart meter deployments is to ensure such expense reductions are reflected in customer rates in a timely manner. While this may seem obvious, this requirement is rarely enforced by regulators. As the Commission is well aware, operating expense reductions are not reflected in customer rates without a rate case. In a rate case, operating expense reductions, such as those which may be available from a smart meter deployment, manifest as a reduction in the revenue requirement, resulting in lower customer rates. Until such a rate case is completed, operating expense reduction benefits accrue to shareholders, not ratepayers.

I have seen investor-owned utilities secure operating expense reduction benefits for shareholders instead of ratepayers in two ways. First, most investor-owned utilities request bill riders to recover the costs of a smart meter deployment. Through the use of a rider, a utility can secure smart meter cost recovery while simultaneously delaying a rate case which would deliver operating cost reductions to customers. (Of note is the Commission's recent decision to deny rider cost recovery for distribution capital in Duke Energy Kentucky's latest rate case.)[6] In my opinion this is the principal reason

[6] Case No. 2017-00321. Commission Order dated April 13, 2018. Page 61.

investor-owned utilities prefer rider cost recovery for smart meter investments. Second, an investor-owned utility can "time" rate cases such that smart meter-related investments have been completed, and reflected in a utility's test year, before the associated operating expense reductions have been executed. Then, once rates are established under the "old" expense scenario, expense reductions are executed and associated economic benefits are enjoyed by shareholders until some subsequent rate case of unknown timing.

In either case, a utility can delay the rate case required to translate expense reductions into rate reductions for customers for many years. As one might imagine, delaying a rate case which translates expense reductions into customer rate reductions by ten years essentially precludes customers from realizing smart meter operating expense benefits for ten years, with accordant detriment to the customer benefit-cost ratio. While no such delay is presented in the Companies' smart meter business case, it is easy to imagine such a delay in practice. For example, the Companies went without a rate case for 5 years between 2003 and 2008. Also of interest is a presentation by the Companies' parent, PPL Corporation, to investors in the most recent earnings call. The presentation indicated more than $1.2 billion in Kentucky investments during 2018 will be followed by capital expenditures of approximately half that amount in year 2022.[7]

This is done to enhance cash flow and rate of return after the rate case, and I imagine the Companies would like to extend such reductions to operating expenses after the rate case for the same reason.

[7] PPL Corporation. Investor presentation accompanying corporate earnings call. May 3, 2018. Slide 16.

Q. Are other circumstances or conditions required to maximize operating expense reductions from smart meter deployments for customers?

A. Yes. In my experience utilities must work very hard to maximize the operating expense reduction benefits which may be available from smart meter deployments. Business processes changes must be designed, functional departments re-organized, staff reductions executed, remaining staff retrained, and new processes ingrained. None of these efforts are easy or inexpensive, and success is not a foregone conclusion. Further, while utility managers are adept at requesting and justifying any staff increases required by smart meters (information technology comes to mind), managers are generally less likely to volunteer staff reductions which smart meters make possible. To summarize, any individual utility's success in securing the level of operating expense reductions projected in its smart meter benefit-cost analysis, in the timeframes indicated in its analysis, is highly variable and far from assured.

Q. Do you have recommendations for the Commission to help ensure customers secure projected operating expense reduction benefits from a smart meter deployment through timely rate reductions?

A. Yes. Regulators in Ohio[8] and Oklahoma[9] have taken steps to secure operating expense reduction benefits from smart meters on behalf of customers in a timely manner, thereby holding utilities accountable for performance. In both cases regulators ordered that utilities' smart meter rider revenue requirements in any year be reduced by the

[8] Ohio PUC 10-2326-GE-RDR. Approved Stipulation. Pages 5-10. February 24, 2012
[9] Oklahoma Corporation Commission 2010-00029. Approved Stipulation. Page 3, Section F. May 27, 2010

operating expense reduction benefits projected by the utilities in their smart meter benefit-cost analyses. For example, if a smart meter benefit-cost analysis forecasted an operating cost reduction of $200,000 in deployment year 5, the regulators' orders reduced the year 5 smart meter rider revenue requirement by $200,000. Without such a mechanism, all the risk of a utility's failure to achieve the projected benefit sizes and timing falls on customers. With such a mechanism, the regulators transferred the risk of securing operating expense reduction benefits of the size and timing projected by utilities from customers to shareholders. I believe it is appropriate for shareholders to bear utility performance risk in exchange for an authorized rate of return. Customers, who pay for smart meters and associated shareholder profits, and whose actions have no bearing on whether or not a utility achieves operating expense reductions of the size or timing projected, should not bear any utility performance risk.

Q. Is there a way to accomplish this transfer of risk from customers to shareholders in situations in which rider cost recovery is not used?

A. Yes. The same effect can be secured by establishing a regulatory liability in the amount of the total nominal operating expense reductions projected by a utility over the benefit-cost analysis period. This regulatory liability can then be amortized over the benefit-cost analysis period as a reduction in revenues once the deployment begins. These reductions, when included in a rate case test period, will serve to reduce the revenue requirement to the extent of operating expense reductions projected by a utility, thereby reducing customer rates and accomplishing the same appropriate transfer of risk from customers to shareholders. Just as with the rider-related revenue requirement reduction, if a utility actually reduces its operating expenses by the amounts and in the timeframes projected in its benefit-cost analysis, the utility still has a fair opportunity to earn its authorized rate of return on equity. That is, reductions in the revenue collected are offset by reductions in operating expenses the Companies expect to secure from the smart meter deployment, and used to support this Application.

Q. What are the Companies' perspectives on the idea of reducing revenue requirements by the amount of savings projected in the Companies' benefit-cost analysis?

A. The Attorney General presented the idea of reducing revenue requirements by the amount of savings projected in discovery. The response was: "The Companies do not believe a commitment in this regard is necessary. If the Companies achieve any AMS operational savings shown in the AMS Business Case, those savings will be implicit in the Companies' future test years and rates."[10] In supplemental discovery on this issue, the response was: "The Companies have publicly stated their intent to file their next base-rate applications no later than September 28, 2018, with a forecasted test year of May 1, 2019, through April 30, 2020 . . . ."[11] I note that neither of these responses includes a commitment that operating savings of the size projected by the Companies will be reflected in the test year of a rate case initiated in the near term. As the Companies control both the timing of operating expense reductions and the timing of rate cases, this lack of commitment increases my concern that shareholders, not

[10] Case No. 2018-00005. Companies' witness Lovekamp response to AG-DR-01 Q.7. April 2, 2018.
[11] Case No. 2018-00005. Companies' witness Lovekamp response to AG-DR-02 Q.6. April 27, 2018.

customers, will reap the benefits of smart meter-related operating expense reductions for many years if the Commission approves the CPCN.

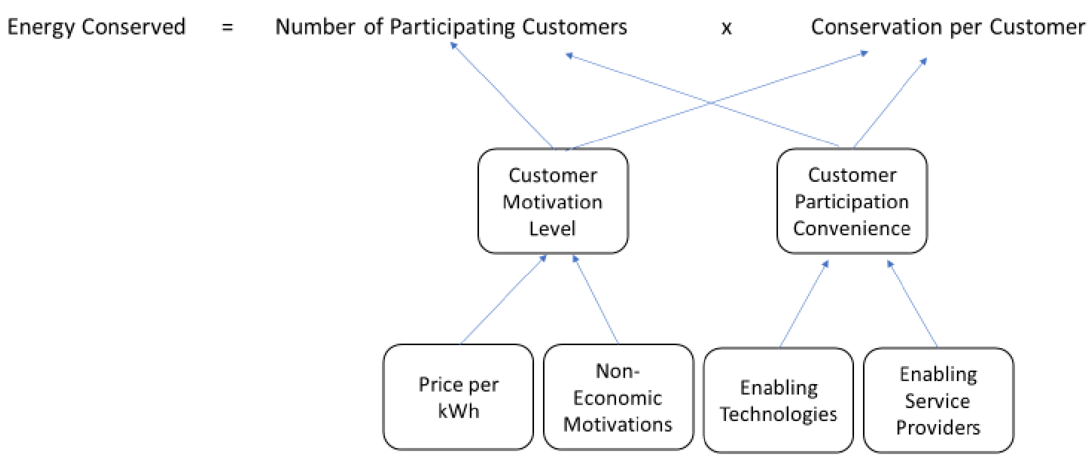
Q. Please describe the circumstances or conditions required to maximize the potential benefits of non-technical revenue loss reductions from smart meters on behalf of customers.

A. In my experience, the maximization of non-technical revenue loss reduction benefit potential from smart meters on behalf of customers requires two things. First, as with operating expense reduction benefits, any such reductions in non-technical revenue losses must be reflected in customer rates in a timely manner. Just like operating expense reductions, a rate case must be completed for any reduction in lost revenues to be reflected in a rate case test year for those benefits to translate into lower customer rates. Until and unless a rate case is held to translate lost revenue reductions into lower customer rates, shareholders, rather than customers, benefit from such reductions. The potential resolutions to this issue are the same as those available for operating expense reduction benefits, including rider revenue requirement reductions or the amortization of a regulatory liability in a rate case test year.

Second, the cost to investigate, estimate, bill and collect lost revenues from offending customers is significant and must be taken into account. In my experience, recovery of theft-related non-technical losses from customers is a very labor intensive, legalistic, and often unsuccessful endeavor. At many utilities the resources expended to collect non-technical losses from offending customers may approach the amounts collected.

Q. Please describe the circumstances and conditions required to maximize customer conservation opportunities from smart meter deployments.

A. Observations from ten years' marketing experience in various industries plus eight additional years' experience developing and launching electric energy conservation programs leads me to conclude that conservation benefit size is correlated with two basic parameters as presented in the diagram below: 1) customer motivation levels; and 2) customer participation convenience.



To summarize, the more motivated a customer is, and the more convenient a customer's participation, the more conservation benefit a smart grid deployment will deliver. Motivation is in turn driven by economic considerations (generally, a higher price per kWh will drive more conservation than a lower price per kWh) and non-economic considerations (such as concern over environmental impact), while convenience is driven by technologies and services which minimize the level of customer effort and attention required to accomplish a given level of conservation.

Q. You mentioned earlier that a key smart meter benefit, which is the opportunity to avoid or delay investments designed to increase system capacity during coincident system peaks, is not available as a result of the Companies' circumstances. Please explain.

A. In my experience, time-varying rates, by virtue of their reduction of customer usage during system peaks, represent the single largest source of economic benefit potential in most smart meter deployments. In most circumstances, the reduction in customer usage during system peaks delays or avoids capital investments otherwise needed to increase system capacity for which customers would have to pay.

Unfortunately, the size of this benefit is limited by the size of system capacity increases which can be delayed or avoided by reducing electric usage during system peaks. I see from the Companies' 2017 Annual Resource Assessment that the Companies' system will have 22.7% excess capacity by 2022.[12] In fact, I see that capacity reduction value is quantified at zero in the Companies' most recent demand-side management program filing.[13] As a result, one of the largest potential economic benefits from a smart meter deployment is not available due to the Companies' extensive excess capacity.

Q. In their Application, the Companies' witness Malloy describes how smart meters are now the dominant form of electric metering in the U.S. What is your reaction to this?

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[12] Case No. 2018-00005. Companies' witness Huff response to AG-DR-02-020.
[13] *Ibid*.

A. The fact that smart meters are popular does not make them appropriate for all situations. Recall that tens of millions of smart meter installations were prompted by the American Reinvestment and Recovery Act, which subsidized their cost by 50%.[14] Since then, investor-owned utilities have seen smart meters as a reasonable regulatory request to increase rate base quickly. Faced with no need for new generation and a 10-year lead time for new transmission, smart meters represented an expedient way to meet shareholders' earnings growth expectations through rapid increases in rate base.

The Companies admitted in discovery they were aware of no independent analyses that indicate the benefits of an actual smart meter deployment exceeded its costs.[15] Conversely, in all three of the only unbiased, comprehensive evaluations of smart grid benefits and costs post-deployment ever conducted, customer costs exceeded customer benefits:

Deployment	Evaluator	Proceeding
Xcel Energy, Boulder CO	Myself and my team	Colorado PUC 11A-1001E
Duke Energy, Cincinnati	Myself and my team	Ohio PUC 10-2326-GE-RDR
Southern California Edison, Los Angeles	Division of Ratepayer Advocates, California PUC	Undocketed case study. March, 2012.

Regulators appear to be approaching large smart meter investments with increasing levels of skepticism. In just the last month, three major IOU smart meter deployment plans were struck down by regulators. The New Mexico Public Regulation Commission rejected Public Service New Mexico's $121 million smart meter proposal

[14] *Recovery Act Selections for Smart Grid Investment Grant Awards - By Category*. Report by the US Department of Energy, Office of Electricity. Accessed via Internet on May 17 at https://www.energy.gov/oe/information-center/recovery-act-smart-grid-investment-grant-sgig-program
[15] Case No. 2018-00005. Companies' witness Malloy response to AG-DR-01 Q.36. April 2, 2018.

after two and a half years of debate, citing 1) the proposal's failure to seize energy conservation opportunities; 2) insufficient operational benefits; 3) high opt-out fees; and 4) the excess of lifetime customers costs over customer savings, particularly in light of shareholder rewards.[16] Just last week, the Massachusetts Department of Public Utilities (DPU) rejected $1.2 billion in smart meter investments proposed by Massachusetts Electric (National Grid) and Eversource (NStar), citing 1) insufficient operating cost reductions (due in large part to existing automated meter reading capabilities); 2) challenges to time-varying rate participation and, on a related note, lack of a uniform approach to customer/third party data access; 3) insufficient capacity cost avoidance benefits; and 4) the high cost associated with the premature retirement of existing metering systems ($210 million, or about 17.5% of full deployment cost).[17] The DPU's order includes an executive summary which reads, in part:

> "Based on a review of the evidence in these proceedings, the Department has determined it must reassess a central objective of D.P.U. 12-76-B, namely strategies for the deployment of advanced metering functionality, in order to maximize the benefits for Massachusetts ratepayers. The Department does not make this decision lightly. The evidence in these cases revealed weaknesses in the business case for advanced metering functionality presented by each company and, therefore, we declined to preauthorize any customer-facing investments at this time. The Department weighed the significant costs associated with full achievement of advanced metering functionality using advanced metering infrastructure against the considerable uncertainty regarding benefits from reduced demand, capacity savings, and customer participation in time varying rates or other forms of dynamic pricing. We determined that the benefits of a full deployment of advanced metering functionality do not currently justify the costs." [18]

[16] New Mexico PRC 15-00312-UT. Order dated April 11, 2018.
[17] Massachusetts DPU 15-120 through 15-123. Order dated May 10, 2018.
[18] *Ibid*. Page 1.

To summarize, I appreciate the fact that the CPCN process in Kentucky provides the Commission with the opportunity to thoroughly scrutinize the Companies' request to install smart meters.

III. ECONOMIC BENEFITS OF THE SIZE PROJECTED BY THE COMPANIES ARE UNLIKELY TO BE REALIZED BY CUSTOMERS

Q. Please explain why you believe economic benefits of the size projected by the Companies are unlikely to be realized by customers.

A. I have carefully examined the Companies' smart meter benefit projections, including information provided in pre-filed testimony and through discovery. I find three of the Companies' specific benefit projections and/or assumptions particularly troubling, and I will address them individually:

- The Companies' use of a 23-year benefit period overstates benefits;
- The Companies' ePortal conservation benefit projections are dramatically overstated, for several reasons to be described further below; and
- The Companies' projections of non-technical loss recovery are dramatically overstated, particularly in light of the Companies' current recovery costs.

THE COMPANIES' USE OF A 23-YEAR BENEFIT PERIOD OVERSTATES BENEFITS

Q. Please describe your concern regarding the Companies' use of a 23-year benefit period to calculate the AMS benefit-cost ratio.

A. It is rational to assume benefits over an asset's useful life[19] when calculating benefit projections. Assuming benefits will continue beyond an asset's useful life overstates

[19] The Financial Accounting Standards Board (FASB) defines useful life as "the period over which an asset is expected to contribute directly or indirectly to future cash flows." Financial Accounting Standard 142.

benefits, as an asset is expected to be replaced (with additional costs incurred) and/or be otherwise unavailable beyond its useful life. In a business case, a utility can assume a longer benefit period than an asset's likely useful life in order to increase projected benefit size. Such increases are not generally warranted.

I know of no IOU which has used a smart meter benefit period longer than 20 years. The table below lists the benefit periods of many publicly-available smart meter business cases.

IOU	State	Docket	Year	Benefit Period	Customers (millions)	Regulatory Approval?
Eversource	MA	15-122	2015	15	1.20	No
Massachusetts Electric	MA	15-120	2015	15	1.32	No
San Diego Gas & Electric^	CA	R08-12-009	2011	15	1.43	Yes
Ameren	IL	12-0244	2012	20	1.22	Yes
ComEd	IL	12-0298	2012	20	3.95	Yes
ConEd	NY	15-E0050	2015	20	3.40	Yes
Duke Energy Ohio*	OH	08-920-EL-SSO	2008	20	0.69	Yes
Duke Energy Carolinas	NC	E7 Sub 1146	2017	20	1.95	TBD
Pacific Gas & Electric	CA	R08-12-009	2011	20	5.43	Yes
KU/LGE	KY	2018-00005	2018	23	0.92	TBD

^ "Terminal Values" (to account for benefits beyond 15 years) also provided for information purposes.

* While a 20-year useful life was assigned to smart meters, the associated communications network was assigned just a 10-year useful life.

Furthermore, a report by the Electric Power Research Institute regarding how to estimate smart grid benefits and costs asserts "Smart grid projects often take a 10 to 20 year perspective for assessing cost effectiveness. Another option is to focus on the expected lifetime of the technologies under consideration and compare the costs and benefits over this time period."[20]

Q. What leads you to believe smart meters will not last the 20-23 years assumed in the Companies' benefit-cost analysis?

A. Several data points lead to my belief that Smart Meters will not last 20-23 years. First, the Companies' own depreciation expert acknowledges, in the Companies' recent rate case, "The most consistent average life within the industry for new technology electric meters is 15 years, with a maximum life potential life of 25 years."[21] In addition, the Companies' own experience with smart meters, from the Responsive Pricing/Smart Meter Pilot from 2007-2009, is troubling. In discovery from the Companies' recent rate case, the Companies reported that of the 1,677 smart meters installed for Pilot, only 376 are still in service as of December 31, 2016.[22] This yields a 7-9 year survival rate of only 22.4%. The Companies explained in discovery in that matter that most smart meters were replaced due to an LCD display failure. While the smart meter manufacturer has likely corrected such an issue by now, the issue is indicative of the more complex and sensitive nature of electronic meters compared to the traditional mechanical type, and why a benefit period of longer than 20 years over-estimates smart

[20] *Methodological Approach for Estimating the Benefits and Costs of Smart Grid Demonstration Projects*. EPRI, Palo Alto, CA: 2010. 1020342. Page 4-57.
[21] Case Nos. 2016-00370 and 2016-00371. Pre-filed direct testimony of Companies' witness John P. Spanos. Page 15, line 7. Nov. 23, 2016.
[22] Case No. 2016-00371. Response to AG-DR-02 Q.94. April 27, 2018.

meter benefits. It is also worth noting that electric cooperative utilities in Kentucky generally depreciate smart meters over a 15-year period.[23]

As further evidence that a 20-23 year life for smart meters may be too long, I cite smart meter manufacturers' standard 5-year warranty offer, which the Companies confirmed in discovery.[24] Further, common sense dictates that challenges to a long life of any sophisticated electronic instrument installed outdoors, from smart meters to the wireless routers and relays which collect smart meter data and transmit it to the Companies, are significant. As just one example, FannieMae guidelines for multifamily property condition assessments recommend a useful life for an outdoor temperature sensor – a much less sophisticated device than a smart meter – of 10 years.[25] Of note, the same guidelines recommend only 20 years' useful life for wood decks. And as anyone who has bought a solar-powered garden light – a device with no moving parts or wireless communications – can attest, useful lives of outdoor equipment are frequently, and frustratingly, short.

Finally, equipment failure is just one of many risks to smart meters' useful lives. There are technology obsolescence risks to a long life for any smart meter deployment. In Ohio, Duke Energy has asked for permission to replace the entire AMS system it completed installing just 4 years ago, including 546,000 meters, 370,000 gas meter

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[23] Commission Order in Case No. 2014-00159 (Cumberland Valley Electric Rate Case). Page 9. See also Case No. 2018-00056, In Re Cumberland Valley Electric Application for CPCN – Automated Metering Infrastructure System, Application, p. 53; and Case No. 2016-00077, Application of Licking Valley RECC for an Order Issuing a CPCN, Company response to AG-DR-02 Q.1(c).
[24] Case No. 2018-00005. Companies' witness Malloy response to AG-DR-01 Q.5. April 27, 2018.
[25] *Instructions for performing a multifamily property condition assessment (Version 2.0)*. Fannie Mae. Appendix F, "Estimated Useful Life Tables". 2014.

index modules, and the entire communications network at a cost of $169 million,[26] or about $245 per customer. The utility's request cites many forms of obsolescence in its testimony, from field data collectors' cellular service mode (2G/3G) to inflexible software (which is unable to bill time-varying rates), to lack of meter and communications device manufacturer support (acquisitions and bankruptcy). The evaporation of manufacturer support, particularly for meter communication networks, is apparently all too common. Landis + Gyr, the Companies' proposed smart meter and communications network provider, is no longer supporting the TS2 meter communications solution it obtained in a 2006 acquisition, in which many utilities had continued to invest as recently as 2016.[27] To summarize, the use of a 15-year benefit-cost period would be a more conservative approach to calculating a smart meter benefit-cost ratio.

Q. By how much does the use of a 15-year benefit period, rather than the 23-year benefit period assumed by the Companies, impact the Companies' AMS benefit projections?

A. The impact of using a 15-year benefit period is very significant, reducing the Companies' present value benefit projections by well over one hundred million dollars. In discovery the Companies were asked to recalculate their benefit-cost analysis over a

[26] Ohio Public Utilities Commission Case Number 17-32. Direct testimony of Donald L. Schneider on behalf of Duke Energy Ohio, Inc. March 16, 2017.

[27] Case No. 2018-00056. Cumberland Valley Electric smart meter CPCN. Exhibit 2, page 1.

15-year period rather than the 23-year period assumed in the Companies' benefit-cost analysis. I used the Companies' response to create the table below.[28]

	Nominal Benefits	Present Value of Benefits
15-year benefit period	$554.9 million	$342.8 million
23-year benefit period[29]	$985.4 million	481.8 million
	($430.5 million)	($139.0 million)

THE COMPANIES' EPORTAL BENEFIT PROJECTIONS ARE DRAMATICALLY OVERSTATED

Q. Please explain why you believe the Companies' ePortal benefit projections are dramatically overstated.

A. As the author of the paper cited by the Companies regarding ePortal benefit calculations,[30] I am familiar with the role of, and the research on, energy usage data feedback in energy conservation. I am also familiar with the benefits of conservation due to years of experience in demand-side management program measurement and verification. I believe the Companies' smart meter conservation benefit projections are

[28] Case No. 2018-00005. Companies' witness Malloy response to AG-DR-02, Question 5. April 27, 2018.
[29] Case No. 2018-00005. Testimony of John P Malloy on behalf of the Companies. Page 15.
[30] Smart Grid Consumer Collaborative. *Smart Grid Economic and Environmental Benefits.* Secondary research conducted by the Wired Group on behalf of the Smart Grid Consumer Collaborative. October 8, 2013.

dramatically overstated for several reasons, which I would like to examine individually in more detail:

- The Companies' conservation benefit projections include non-fuel cost reductions which will never be secured;
- The Companies' assumptions regarding customer motivation to participate, and therefore customer participation levels, are overly aggressive;
- The Companies' conservation rate estimate assumes no change in customer rate design over the 23-year benefit period, an assumption which may not hold;
- The Companies incur an economic penalty by maximizing the energy conservation benefits of the ePortal, discouraging conservation maximization;
- The Companies' assumptions regarding customer participation convenience, and therefore conservation per participant, are aggressive.

Q. Please explain why the Companies' conservation benefit projections include non-fuel cost reductions which will never be secured.

A. The Companies base their conservation benefit assumptions on an average customer's bill.[31] By extension, this means the Companies assume a 3% conservation effect will deliver economic benefits to customers equal to 3% of the Companies' costs.

In the long run, however, energy conservation only reduces the Companies' fuel costs. Conservation does not reduce the Companies' non-fuel costs, like investments in

[31] Case Nos. 2016-00370 and 2016-00371. Testimony of John P. Malloy on behalf of the Companies. Exh. JPM-1. Page 157.

generation, transmission, and distribution, or like operating expenses and administrative costs. As fuel costs are passed along to customers on a dollar-for-dollar basis in Kentucky, reductions in Company fuel costs directly benefit customers in the short term and the long term. However, since conservation does not reduce the Companies' non-fuel costs, the Companies' assumption that a 3% conservation effect will result in a 3% bill reduction for customers is only correct in the short term, until the next rate case. At that point, after rates are adjusted for changes in the volume of kWh sold, the only conservation benefits customers will continue to enjoy are fuel cost reductions. As fuel costs are the only actual cost reductions from conservation, only fuel costs should be included in the Companies' ePortal conservation benefit projections.

Q. What is the magnitude of this challenge to the Companies' conservation benefit projections?

A. In discovery, the Companies provided fuel and non-fuel revenue forecasts for the RS (residential) rate class throughout the benefit-cost analysis period. An analysis of this data indicates that, on average during this period, non-fuel revenues will be 71% of total revenues.[32] Since non-fuel costs do not actually fall with conservation, I believe the Companies' benefit projections from conservation to be overstated by 71%. By applying the 71% non-fuel revenue ratio to the Companies' nominal ePortal benefit projection of $158 million, I estimate the Companies' ePortal benefit projection to be overstated by about $112 million for this issue alone. (Note that this figure does not

[32] Case No. 2018-0005. Companies' witness Malloy response to AG-DR-01 Q.24. April 2, 2018.

include other ePortal conservation benefit assumptions which may be overstated, such as the estimate that 17% of customers will become active ePortal users.)

Q. Please explain why you believe the Companies' assumptions regarding customer motivation to participate, and therefore customer participation levels, are extremely aggressive.

A. As indicated in my testimony above on the requirements for smart meter benefit maximization, smart meter conservation benefits are maximized when customers are motivated and program participation is convenient. The Companies' conservation benefit projections assume customer motivation levels, and therefore customer participation, that are unreasonably high.

The Companies' conservation benefit projections assume that 17% of customers will become active users of the Companies' ePortal. The assumption is derived from the fact that 48% of the customers participating in the AMS Customer Offering accessed MyMeter (a capability like the proposed e-Portal), and that 36% of these users visit MyMeter frequently enough to be considered "active users". However, the estimate was derived from customers already participating in the AMS Customer Offering. One could very reasonably argue that customers participating in the AMS Customer Offering are already among the most motivated and energy-conscious consumers in the Companies' entire customer population. Assuming that customers in the Companies' general population will become active ePortal users at the same rate exhibited by AMS Customer Offering customers is clearly not a valid assumption.

I suggest the rate at which customers participated in the AMS Customer Offering to be a much more valid estimate of the rate at which customers in the general population would become active ePortal users. Customers participating in the AMS Customer Offering are likely to be the same types of customers likely to access the ePortal; that is, highly motivated and energy-conscious. I note that the conservation analysis commissioned by the Companies does not address the question of customer participation rate. Rather, it purports to show the change in usage (conservation effectiveness) between active MyMeter users and others within the population of AMS Customer Offering customers, delivering a conservation estimate (3.8%) to be applied to active ePortal users post smart meter deployment (that is, the Companies' estimate of 17%). The analysis does not address the question of how many customers are likely to take the time to access the ePortal frequently and use it to conserve energy.

In discovery, the Companies report that 7,817 customers were participating in the AMS Customer Offering as of March 31, 2018. With approximately 796,171 residential electric customers in Kentucky between the Companies,[33] the AMS Customer Offering participation rate is almost exactly 1% (0.9818%). This participation rate was secured after almost 2.5 years of heavy promotion, which was described by the Companies through discovery as "email, online advertising, search engine marketing, social media, and direct mail items like bill envelopes, bill inserts, and customer newsletters".[34] It is also interesting to note that 52% of AMS Customer Offering participants – arguably among the most motivated and energy conscious of all the Companies' customers –

[33] Case No. 2018-00005. Companies' witness Huff response to AG-DR-02 Q.7. April 27, 2018.
[34] Case No. 2018-00005. Companies' witness Huff response to AG-DR-01 Q.10. April 2, 2018.

never accessed MyMeter at all. Based on these observations, it is difficult to imagine how increased promotional efforts will increase the number of highly motivated and energy conscious customers from 1% (AMS Customer Offering participation rate) to 17% (the Companies' projection of active ePortal users from the general customer population in a smart meter deployment).

Q. Please explain how the Companies' conservation benefit projections could be impacted by changes in customer rate design.

A. While I assert that the Companies' conservation benefit projections should not include reductions in non-fuel costs which are unaffected by conservation, I do appreciate that the opportunity for individual customers to reduce the size of their bills by a full charge per kWh, probably about $0.12 per kWh currently, presents a short-term incentive to conserve. The Companies' conservation benefit projection per active ePortal user of 3% reflects the current level of incentive presented by the current rate design.

However, various rate designs the Companies could request in the future would serve to reduce customer conservation incentives, thereby making the 3% conservation estimate too high. In their most recent rate cases, for example, the Companies requested a "Basic Service Charge" be added to the tariff. The purpose of the Basic Service Charge was "to begin to educate customers . . . about the two kinds of costs (fixed and variable) recovered through the Company's volumetric energy charge."[35] It could be argued that this education is designed as the first step to the eventual introduction of a straight-fixed-variable rate design, which would result in a significant reduction in the

[35] Case Nos. 2016-00370 and 2016-00371. Direct testimony of Robert M. Conroy. Page 9, line 24.

volumetric rate per kWh and a corresponding reduction in customers' conservation incentive. As another example, the Companies recent rate case requested a significant change in the customer charge, from $10.75 to $22.00.[36] Like straight-fixed-variable rate design, increases to the customer charge also result in a reduction of the volumetric rate per kWh, again with a corresponding reduction in customers' conservation incentive.

As customers' conservation incentives fall, the amount of conservation motivation falls. This causes any conservation rate estimates based on the current level of conservation incentive, such as the 3% assumed by the Companies in their ePortal conservation benefit estimate, to be overstated. Because the Companies have a strong motivation to reduce the portion of their revenue requirement collected through volumetric rates, the assumption that the current rate structure of comparatively high volumetric rates will remain in place over the 23 years covered in the smart meter benefit-cost analysis period is unlikely to hold. In turn, any conservation rate estimate the Companies make for the ePortal which assumes the customer conservation incentive will remain as strong as it is today for the next 23 years is also unlikely to hold. This calls into question the 3% ePortal conservation rate estimate in the Companies' conservation benefit incentive calculation.

Q. Please describe how the Companies incur an economic penalty by maximizing the energy conservation benefits of the ePortal.

[36] *Ibid*. Page 10, line 5.

A. Maximizing the energy conservation benefits of the ePortal specifically, or of smart meters generally, penalizes the Companies economically because conservation decreases sales and reduces the likelihood that the Companies will earn the rate of return on equity the Commission has authorized. As difficult as achieving the ePortal benefits projected by the Companies will be, due to the challenges I describe above, the Companies will be economically penalized if they are somehow able to achieve the conservation benefit estimates. With an economic penalty to pay and significant challenges to overcome, there is little hope the Companies will secure anything close to the $158 million dollars in nominal conservation benefits from smart meters over the 23-year benefit period.

Q. Please explain why the Companies' assumptions regarding customer participation convenience, and therefore conservation per participant, are aggressive.

A. As indicated in my testimony above on the requirements for smart meter benefit maximization, smart meter conservation benefits are maximized when customers are motivated and program participation is convenient. Research indicates that conserving energy through detailed billing data presented online is anything but convenient, requiring a highly motivated and dedicated customer. In the secondary research cited by the Companies in support of their "conservative" 3% conservation estimate, Darby takes pains to point out that findings of 5%-15% conservation effects from energy usage feedback is specifically associated with direct, immediate feedback by means of an in-home display.[37] Darby describes website data presentation of the type proposed by the

[37] Darby, S. *The Effectiveness of Feedback on Energy Consumption.* Environmental Change Institute, University of Oxford. April 2006. Page 3.

Companies in their ePortal as “indirect” feedback, which requires significant customer motivation, effort, and dedication to employ successfully for conservation. While this secondary research indicates a potential conservation impact from indirect feedback, Darby states “Savings have ranged from 0-10%, but they vary according to context and the quality of information given.”[38] Later in the paper, Darby describes “context and quality” more succinctly as “analysis and advice” which must accompany the indirect usage data feedback to secure any conservation benefits: “While online billing can provide a useful interactive feedback service and can incorporate analysis and advice, it is unlikely to be an adequate substitute for a direct display.”[39] Darby also notes in a related secondary research paper, regarding Internet-based data availability, “The research literature to date, largely based on the use of utility websites, suggests that this type of feedback is mostly for enthusiasts”.[40]

Other forms of direct, immediate feedback with which I am familiar include “high bill alert” texts of the type offered by Southern California Edison in its *Budget Assistant* service,[41] or a special lamp in the home which glows when conservation is recommended. In these direct forms of feedback, no website need be visited and no data need be analyzed; alerts are immediate and convenient. The common thread to direct energy feedback approaches is that, once established, the mechanism to alert a customer of a conservation opportunity is convenient, and occurs without prompting,

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[38] *Ibid*.
[39] *Ibid*, page 4.
[40] Darby, S. *Literature Review for the Energy Demand Research Project.* Environmental Change Institute, University of Oxford. Undated. Page 20.
[41] Accessed via Internet May 10, 2018 at https://www.sce.com/wps/portal/home/residential/rebates-savings/budget-assistant-and-you/

analysis, or additional customer effort. As the Companies propose no direct feedback as part of their smart meter or ePortal offering, nor any "analysis and advice" as recommended by Darby, I do not believe significant conservation benefit claims are warranted. To their credit, the Companies assume only a 3% level of conservation benefit among active ePortal users.[42] However, I know of no well-controlled study which indicates that accessing energy usage data alone via an internet-based portal delivers any statistically significant conservation at all, let alone 3%.

Q. But what of the Companies' independent analysis, which found a 3.8% improvement in conservation from active ePortal users vs. non-active users?

A. I have several concerns with the independent analysis commissioned by the Companies to investigate the conservation improvement among active ePortal users. First, I note that both active and non-active user groups appeared to conserve energy in the "post" period; the question becomes, is the difference in conservation between the groups statistically significant? As noted by the Companies' consultants, the small sample size of the contrast group and the "noisiness" of the data (wide degree of variability) makes household-level conservation difficult to discern.[43] The Companies' consultants presented the results of the PRISM approach to modeling data, as the PRISM approach creating a model offering less variability in model outcomes than other approaches. Using the PRISM approach, the difference in conservation between the active users and non-active users appeared statistically significant (that is, the apparent relationship

[42] Case Nos. 2016-00370 and 2016-00371. Testimony of John P. Malloy on behalf of Companies. Exh. JPM-1, page 157.
[43] Case No. 2018-20005. *2017 Analysis of AMS MyMeter Active Users.* Testimony of John P. Malloy on behalf of the Companies. Exh. JPM-1, Appendix A-10. January 3, 2018. Page 2.

between active users and increased conservation as suggested by the model is likely to be "real" and less likely to be mere coincidence). However, the use of another common approach to modeling data – the Fixed Panel Effects approach – delivered a result in which the difference in conservation between the groups was not statistically significant (that is, the relationship between active users and conservation appeared less likely to be "real", and more likely just a coincidence). To summarize, the determination of whether or not the conservation difference between the active and non-active ePortal users is "real" or not is based largely on which modeling approach the Companies' consultants chose to use. This is obviously concerning.

Another of my concerns has to do with the percentage of customers removed from the analysis due to "extreme change in estimated annual pre-post consumption." The definition of extreme change chosen by the Companies' consultant was "the highest and lowest 1% of the distribution (of customers)".[44] While this definition seems reasonable, it resulted in only 4.5% of the customers being removed from the active user group (116 of 2,569), but over 13% of the customers being removed from non-active user group (57 of 428).[45] When these concerns were pursued in discovery, the Companies corrected screening data, reporting that 47.3% of customers in the active user group (1,216 vs only 116 previously) and 16.6% of the non-active user group had been removed. The Companies claimed the correction "does not change the impact findings of the Tetra Tech analysis,"[46] yet they did not provide updates to the report or statistical analysis outcomes.

[44] *Ibid.* Page 5.
[45] *Ibid.*
[46] Case No. 2018-00005. Company witness Huff responses to AG-DR-02 Q.10. April 27, 2018.

To summarize, I do not believe the independent analysis to be convincing enough to rely upon the finding of a 3.8% incremental conservation impact among active users.

THE COMPANIES' NON-TECHNICAL LOSS RECOVERY BENEFITS ARE DRAMATICALLY OVERSTATED

Q. Please describe the concept of non-technical losses.

A. Non-technical losses, also known as unaccounted-for energy, is energy that is not billed. Theft and meter errors are the largest sources of non-technical loss.[47]

Q. Please describe your concerns regarding the Companies' non-technical loss recovery benefit projections.

A. In the AMS business cases I have reviewed, the benefit projections for non-technical loss (NTL) recovery are among the most variable of any AMS capability. However, of all the AMS business cases I have ever reviewed, the Companies' non-technical loss recovery benefit projections are among the most aggressive. The Companies assume both a high level of non-technical losses to begin with (2%), as well as a high loss recovery rate (36%).[48] In the table below I have summarized the non-technical loss and recovery rate assumptions of recent smart meter business cases.

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[47] Case Nos. 2016-00370 and 2016-00371. Testimony of John P. Malloy on behalf of the Companies. Exh. JPM-1. November 23, 2016. Page 35.
[48] *Ibid*. Page 158.

	State	Docket	Year	Stated Theft & Recovery Assumptions	PV of NTL Recovery (millions)	Recent Year 12 months' electric revenues (billions)[49]
Ameren	IL	12-0244	2012	Theft = 1%; recovery = 25%	19.8	1.683
ConEd	NY	15-E0050	2015	Theft = 1%; recovery = 25%	870.0	8.172
Mass Electric	MA	15-120	2015	Res theft 1.5%; Comm'l 1% (recovery not available)	168.7	2.522
KU/LG&E	KY	2018-00005	2018	NTL = 2%; recovery = 36%	196.8[50]	2.438[51]

Also of significant interest on this issue is a presentation delivered by the Companies to the Association for Community Ministries in 2009, obtained in discovery in the Companies' latest rate case. This presentation appears to be the final product of a work team, assisted by Accenture Consulting, assigned to develop a business case for smart meters/grid for E-On/US, former owners of the Companies. Dated May 6, 2009, the report estimates the 25-year present value of combined "system losses" and "revenue protection" benefits to be only $28 million.[52] It is notable that just a few years ago, a team investigating the net technical loss recovery benefits from AMS for the Companies found those benefits to be less than 15% of the benefits projected by the

[49] SEC Forms 10-K unless otherwise noted. Ameren 2015; Consolidated Edison 2015.
[50] Case No. 2018-00005. Testimony of John P. Malloy on behalf of the Companies. January 10, 2018. Page 15.
[51] Case No. 2016-00371. Companies' response to PSC DR 1-54 for KU + LG&E, tab "SCH C-1".
[52] Case No. 2016-00371. Companies' response to ACM DR 1-33. Page 14.

Companies in the current AMS business case. I should also point out that "system losses" could have been defined to include technical (in addition to non-technical) losses, making the AMS non-technical loss recovery benefit appear even more aggressive relative to the 2009 E-On/US estimate.

Q. How great an overstatement do you believe is included in the Companies' non-technical loss recovery benefit projection?

A. It is not simply the size of the non-technical loss recovery that concerns me. Also problematic in my opinion is the fact that today, the Companies spend over $0.50 in operating expenses for every $1 in non-technical losses they recover on average:

	2017
Revenue Assurance O&M[53]	$377,000
Losses Identified and Billed[54]	$1,221,770
Anticipated Collections (60%)[55]	733,062
Spending per $1.00 Recovered	$0.51

I am not surprised by this finding. In my experience the recovery of non-technical losses is an extremely labor and litigation-intensive process involving distinct loss investigation, estimation, billing, and collection activities. However, despite a projected 24-fold increase in lost revenue recovery from $733,000 per year (2017) to a projected $17.5 million per year on average over the smart meter benefit-cost analysis period,[56] and despite the current expenditure of $0.50 for every $1.00 in lost revenues

[53] Case No. 2018-00005. Companies' witness Malloy response to AG-DR-01 Q.23. April 2, 2018.
[54] Case No. 2018-00005. Companies' witness Malloy response to AG-DR-02 Q.15. April 27, 2018.
[55] Case No. 2018-00005. Testimony of John P. Malloy on behalf of the Companies. Page 17, line 14.
[56] Case No. 2018-00005. Companies' witness Malloy response to PSC-DR-01, Q.24. April 2, 2018.

recovered, and despite the fact that the Companies admit the lost revenue recovery process will remain largely the same after a smart meter deployment as it exists today[57] (apart from the improved identification of theft), the Companies project no increase in revenue protection department expenditures.[58] The fact that lost revenue recovery benefit estimates are not calculated net of collection costs we know to be significant, and the fact that no provision for increases in revenue assurance operating expenses is included in smart meter operating expense detail, indicates the lost revenue recovery benefit projection is dramatically overstated.

Q. Do you have other support for your conclusion that the lost revenue recovery benefit is dramatically overstated?

A. Yes. As with the failure to reflect revenue assurance operating expense increases in its smart meter benefit-cost analysis, the Companies' projections simply do not match up to current experience. For example, the Companies claim they can collect 60% of lost revenues identified and billed.[59] In order to collect an average of $17.5 million a year, this means that the Companies would have to identify and bill $29.2 million in lost revenues annually. In discovery, the Companies reported that in 2017 (as an example), they identified and billed 9,315 incidents of meter tampering or unbilled revenues at an average of $131.16 per incident.[60] To reach $29.2 million in lost revenues identified and billed at $131.16 per incident, the Companies would have to identify and bill 222,375 incidents annually, or 27.9% of the Companies' residential customers. To

[57] Case No. 2018-00005. Companies' witness Malloy response to AG-DR-01 Q.22. April 2, 2018.
[58] Case No. 2018-00005. Companies' witness Malloy response to PSC-DR-01 Q.48. April 2, 2018.
[59] Case No. 2018-00005. Testimony of John P. Malloy on behalf of the Companies. Page 17, line 14.
[60] Case No. 2018-00005. Companies' witness Malloy response to AG-DR-02 Q.15. April 27, 2018.

summarize, between the outsized theft and recovery projections, the failure to account for significant increases in revenue assurance expenses, and the disconnect between current experience and the Companies' benefit projections, the Companies' lost revenue reduction benefit calculations simply do not pass a "smell test". I consider the Companies' lost revenue reduction benefit projections to be significantly overstated.

IV. THE COMPANIES' COST ESTIMATES ARE SIGNIFICANTLY UNDERSTATED

Q. Why do you believe the Companies' smart meter cost estimates are significantly understated?

A. There are two reasons why the Companies' smart meter cost estimates are significantly understated, which I would like to address individually:

- The Companies' nominal cost projections do not appear to include carrying costs (profits, taxes on profits, interest expense, and property taxes) customers will be asked to pay.
- The Companies' cost projections do not include the cost recovery (or associated carrying costs) on meters currently in service which would be prematurely retired under the Companies' proposal.

Q. Why do you believe the Companies' nominal cost projections do not include carrying costs (such as profits, taxes on profits, interest expense, and property taxes) customers will be asked to pay?

A. ~~The Companies claimed in discovery that the Companies' $379.4 million capital cost present value projections, including $357.1 million present value in initial project capital and an additional $22.3 million present value in capital over the life of the project, did include carrying costs.[61] However, I am skeptical of this claim. First,~~

~~[61] Case number 2018-00005. Response of Companies' witness Malloy to AG-DR-01, Q. 20(a). April 2, 2018.~~

~~carrying costs are not included in the list of costs described by the Companies in testimony.~~[62] ~~Second, the Companies' response to other questions in this line of discovery are suspect.~~ In discovery, the Companies were ~~For example, when~~ asked to restate the cost-benefit table for reductions in the corporate tax rate from 35% to 21% recently enacted by the U.S. Congress (the Tax Cuts and Jobs Act, or "TCJA"). ~~, t~~The Companies responded with a nominal capital cost ~~present value~~ projection ~~almost~~ $~~200~~214 million dollars higher than the initial nominal capital cost projection.[63] I do not understand how a reduction in the corporate tax rate could possibly lead to an increase in nominal capital cost ~~present value~~ projections if both the initial and TCJA nominal capital cost ~~present value~~ projections included carrying costs. I suspect that the Companies used the opportunity presented by the TCJA ~~discovery~~ to add carrying costs to their initial nominal capital cost ~~present value~~ projections.

~~When pressed for additional details in supplemental discovery, the Companies responded with a level of detail which did not conclusively prove that carrying costs were included in the initial capital cost present value projections of $379.4 million either~~.[64]

~~Regardless of these concerning discrepancies,~~ I submit that the Commission should use the nominal capital cost ~~present value~~ amounts projected by the Companies~~'~~ in response to the TCJA ~~discovery~~, which clearly do include carrying costs customers will be asked to pay, in the Commission's evaluation of the Companies' smart meter CPCN. I

~~[62] Case No. 2018-00005. Testimony of Companies witness John P. Malloy. January 10, 2018. Page 14.~~

[63] Case No. 2018-00005. Response of Companies' witness Malloy to AG-DR-01 Q.20(c). April 27, 2018.

~~[64] Case No. 2018-00005. Worksheets provided with the response of Companies witness Malloy to AG-DR-02 Q.12(a). April 27, 2018.~~

prepared the table below from information provided in testimony and subsequent discovery in this matter.

	Nominal Capital[65] ~~(for reference)~~	~~Present Value Capital (carrying costs included per discovery)~~[66]	TCJA[67] ~~Present Value~~ Nominal Capital	Difference between initial and TCJA ~~Present Value~~Nominal Capital
Initial Project Capital	320.0	~~357.1~~	515.0	195.0~~57.9~~
Ongoing Capital Requirements	43.8	~~22.3~~	63.0	~~40.7~~19.2
Total Capital Requirements	363.8	~~379.4~~	578.0	~~198.6~~214.2

As one can see from the table above, the Companies' projection for Nominal~~Present Value~~ Capital after the TCJA, which ostensibly does include carrying costs to be paid by customers, is $214.2~~198.6~~ million greater than the Companies' initial Nominal~~Prevent Value~~ Capital projection of $363.8~~79.4~~ million. I believe the Commission should consider that the cost to be recovered from customers if the Commission approves the smart meter CPCN will be $214.2~~198.6~~ million higher than the cost the Companies presented in the initial application here.

[65] Case No. 2018-00005. Testimony of Companies witness John P. Malloy. January 10, 2018. Page 15.
~~[66] Case No. 2018-00005. Response of Companies' witness Malloy to AG-DR-01 Q.20(a). April 2, 2018~~
[67] Case No. 2018-00005. Response of Companies' witness Malloy to AG-DR-01 Q.20(c). April 2, 2018.

Q. Why do you believe the Companies' cost projections should include the cost recovery (and associated carrying costs) on meters currently in service which would be prematurely retired under the Companies' proposal?

A. For multiple decades now, state utility regulators have prohibited, or attempted to prohibit, investor-owned utilities from collecting revenues twice for the same asset. The issue of "double cost recovery" has come to a head most commonly during utility requests for "rider" cost recovery. Rider cost recovery involves the use of "pre-approved" increases in revenue requirements for certain extraordinary capital investments outside of a rate case through a distinct line item, or "rider", on customer bills. Among the many legitimate issues consumer and business advocates have with such riders is that it is difficult to avoid "double recovery"; that is, it can be difficult for an advocate to ensure that assets for which costs are being recovered through a rider aren't also being included in a utility's rate base for cost recovery through a traditional rate case.

The Companies' proposal to install new meters when the existing meters are currently functioning adequately amounts to double cost recovery. I imagine that the Companies will disagree that their proposal represents double cost recovery. I can appreciate that from a utility's perspective, utility costs would have legitimately increased (there would then be two (2) sets of assets on the books, "old" meters and "new" meters), and that the costs of both retired and new meters must be collected from customers. I can see, from the utility's perspective, that this is different from collecting for the same asset twice.

However, I think customers would see things more than a little bit differently. If a customer is already paying for an asset that adequately reads his or her electric usage, why should that customer pay for a second asset to read electric usage? Why pay for two assets to perform the function of one asset? Would a rational consumer buy a second car if he or she had no use for a second car? When viewed from the customer's perspective, it is easy to see how the Companies' CPCN could be considered double cost recovery.

Q. What is the Companies' position on this issue?

A. The Companies' position on this issue has varied. In its initial smart meter request in the recent rate case, the Companies did include the cost of premature meter retirement in their benefit-cost analysis.[68] In the present CPCN, the Companies do not include the cost of premature meter retirement in their benefit-cost analysis.[69] In testimony, the Companies explain the change due to the fact that in the rate case request, the Companies asked to accelerate cost recovery of retired meters, while here, the Companies offered to recover the cost of retired meters over those meters' remaining useful lives.[70] However, the customers are losing the value of the prematurely retired meters, and are paying for the prematurely retired meters, in either case. The question of whether a request for accelerated cost recovery is involved or not appears inconsequential to me. In fact, by leaving the value of retired meters on the books

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[68] Case Nos. 2016-00370 and 2016-00371. Testimony of John P. Malloy on behalf of the Companies. Exhibit JPM-1. November 23, 2016. Page 38.

[69] Case No. 2018-00005. Testimony of John P. Malloy on behalf of the Companies. Exhibit JPM-1. January 10, 2018. Page 45.

[70] Case No. 2018-00005. Testimony of John P. Malloy on behalf of the Companies. Page 12, line 17. January 10, 2018.

longer, the Companies are increasing profits over what they would receive had cost recovery been accelerated, and increasing associated customer carrying costs too.

Q. What is the size of the impact of removing the cost recovery of prematurely retired meters from the Companies' projected costs?

A. In the rate case request for smart meters, the Companies indicated a book value for prematurely retired meters of $39.7 million.[71] In discovery in that case, the Companies confirmed the $39.7 million nominal cost included in the customer benefit-cost analysis did not include carrying costs,[72] so the ultimate impact of ignoring the cost recovery for prematurely retired meters is likely greater than $39.7 million.

Asking customers to pay for two sets of meters simultaneously without including both sets of costs in a customer benefit-cost analysis is not appropriate. Regulators in at least one other state agree with my perspective. The Massachusetts Department of Public Utilities (DPU) considered this issue extensively in a recent round of grid modernization requests by investor-owned utilities in that state. Though the DPU initially ruled that the recovery of costs from prematurely-retired meters should be excluded from customer benefit-cost calculations,[73] the DPU's final order on grid modernization planning determined that such costs should simply be quantified for consideration (outside of the benefit-cost analysis).[74] However ultimately, after confronting the size of the stranded meter costs ($210 million, or about 17.5% of total

[71] Case Nos. 2016-00370 and 2016-00371. Testimony of John P. Malloy on behalf of the Companies. Exhibit JPM-1. November 23, 2016. Page 38.
[72] Case No. 2016-00370, response by Companies' witness Garrett to AG-DR-01 Q.298; Case No. 2016-00371, response by Companies' witness Garrett to AG-DR-01 Q.323. January 11, 2017.
[73] Massachusetts DPU 12-76-c. Order dated November 5, 2014. Page 27.
[74] *Ibid*. Page 28.

utility smart meter nominal capital costs), the DPU rejected all three smart meter deployment proposals due in part to the high cost of retiring meters prematurely.[75] The Companies' case, in which stranded costs represent 10.9% of nominal project capital costs, is not so much different.

Q. How do you respond to the Companies' claim that the impact on the average residential customer's bill if the CPCN is approved will only be $2.60 per month?

A. In discovery, the Companies provided details on the $2.60 average monthly bill impact estimate which appeared to indicate that the bill impact estimate was net of benefits assumed by the Companies in their benefit-cost analysis.[76] As indicated in the previous section of my testimony, I believe these benefit projections to be inflated by hundreds of millions of dollars. I also note that the $2.60 average monthly bill impact estimate was presented in the initial application, and does not therefore include the $198.6 million increase in capital cost present value (a 52% increase over the initial capital cost present value) the Companies associate in discovery with the federal corporate tax reductions recently passed by the U.S. Congress (but which I believe to represent carrying costs customers must pay). As a result of these deficiencies, I recommend the Commission disregard the Companies' $2.60 average monthly bill impact estimate.

[75] Massachusetts DPU 15-120 through 15-127. Order dated May 10, 2018. Page 122.
[76] Case No. 2018-00005. Response by Companies' witness Malloy to AG-DR-01 Q.21(a). April 2, 2018.

V. REVIEW AND CONCLUSIONS

Q. Can you summarize your testimony?

A. In this testimony I recommend the Commission reject the Companies' smart meter CPCN request based on three claims: 1) despite their popularity, a favorable customer benefit-cost ratio from smart meters is not always possible, and involves requirements and conditions not available in the Companies' CPCN or circumstances; 2) the Companies' customer benefit-cost analysis overstates benefits by hundreds of millions of dollars; and 3) the Companies customer benefit-cost analysis understates costs by hundreds of millions of dollars.

Q. What are your principal arguments that certain requirements or conditions not available in the Companies' CPCN or circumstances make a favorable customer benefit-cost ratio unlikely?

A. One argument relates to the timing of benefits and the timing of rate cases. I noted that the timing of operating expense and lost revenue reduction benefits is controlled by utilities, and that rate case timing is also controlled by utilities. I also noted that a rate case test year which reflects reduced revenue requirements from both these types of benefits is required for the benefits to translate into customer rate reductions. My concern is that utilities are controlling benefits such that they are delivered after a rate case or rider is used to recover smart meter capital costs and profits in rates. In this manner the savings from these particular benefit types accrue to shareholders rather than customers until some subsequent rate case of unknown timing. In the Companies' case I note that operating expense and lost revenue reduction benefits amount to 84% of the $985.4 million in benefits projected by the Companies, meaning that even inadvertent exploitation of this opportunity in even small proportions would have significant impact to customers' realized benefits post-deployment.

In a second argument I noted that the single largest potential benefit in most smart meter deployments lies in the power of time-varying rates (which smart meters enable) to change customer usage behavior during system peak periods. Reductions in electric use during system peak delay or avoided capacity increases and associated costs, assuming such capacity increases are required. Given the large amounts of excess capacity currently available in the Companies' system, such cost delays or avoidances are not available. As a consequence, the benefits normally associated with time-varying rates are not available to the Companies' customers from a smart meter deployment.

Q. What are your principal arguments that the Companies' benefit-cost analysis overstates benefits by hundreds of millions of dollars?

A. I provide several primary arguments in support of my belief that the Companies' benefit-cost analysis overstates benefits by hundreds of millions of dollars.

- The Companies artificially inflate smart meter benefits by using a benefits period that is three years (15%) longer than the longest of which I am aware (20 years).
- The Companies' assumption that 17% of customers in the general customer population will become active ePortal users is not at all realistic. I compared

the assumed 17% active user rate to the enrollment rate of the Companies' AMS Customer Offering, which stands at 1% after almost 2.5 years of extensive promotions across multiple customer communication channels.

- The Companies include non-fuel expense reductions from ePortal conservation in benefit projections, despite the fact that non-fuel expenses are not influenced by conservation. I noted that 71% of the Companies' forecasted revenues are associated with the recovery of non-fuel costs, meaning that the Companies' ePortal conservation benefit is inflated by approximately 71%, or $112 million.

- The Companies' ePortal conservation benefit estimates assume that the current level of customer conservation incentive will remain the same despite recent requests the Companies have made to reduce the ratio of costs recovered through a volumetric charge ($/kWh). Customers' incentive to conserve will fall with any change in the rate structure which reduces the volumetric charge, meaning that the Companies' conservation benefit estimates are likely to be too high relative to the rate structures which could prevail in the future.

- The Companies will be economically penalized if the ePortal is as successful at conservation as the Companies claim it will be, meaning that the Companies have no incentive to ensure the ePortal delivers the high levels of benefits projected.

- The Companies' projections for lost revenue reduction benefits are too high, as they do not reflect significant collection costs. In 2017 the Companies' investigation, estimation, billing, and collection costs amounted to more than

$0.50 for every $1 in lost revenues recovered. Despite a 24-fold increase in recovery, I could find no expense increases for the Revenue Assurance department in the Companies' Application or in subsequent discovery conducted by intervenors, nor any "netting" of such costs against projected benefits.

- The Companies' projections for lost revenue reduction benefits also fail to reflect current operational realities. Based on current statistics from the Companies' Revenue Assurance department, I showed that 222,375 cases of theft and tampering would need to be identified and billed per year to collect the $17.5 million per year in benefits the Companies project (with collections amounting to 60% of case billings). With the current number of customers the Companies have, it does not seem possible that 222,375 cases of theft or tampering will be identified and billed annually.

Q. What are your principal arguments that the Companies' cost projections are understated by hundreds of millions of dollars?

A. In support of my claim that the Companies' cost estimates are understated by hundreds of millions of dollars, I noted that the Companies did not include $~~198.6~~214.2 million in carrying costs customers will be asked to pay (though the Companies did provide ~~attribute~~ these cost adjustments when updating for~~to~~ the federal income tax *reductions* recently passed by the U.S. Congress). In addition, I noted that the Companies ignore at least $39.7 million in book value customers will have to pay on meters retired from service prematurely. Finally, I provided information indicating that the Companies' maximum average residential bill impact estimate of $2.60 is not reliable.

Q. Do you have any concluding thoughts?

A. In conclusion, I recommend that the Commission reject the Companies' CPCN for smart meters based on the information provided in this testimony.

Q. Does this conclude your testimony?

A. Yes, it does.

APPENDIX A: CURRICULUM VITAE OF PAUL J. ALVAREZ

Curriculum Vitae -- Paul J. Alvarez MM, NPDP

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Profile

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

Research Projects, Thought Leadership, Regulatory Appearances

Support for Considering 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; also 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 in A16-09-001. May 2, 2017.

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

Evaluation of Eversource's Smart Meter Deployment Plan. Testimony before the Massachusetts Department of Public Utilities on behalf of the Attorney General in 15-122. March 10, 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

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 Request 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.

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

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

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.

Best Practices in Grid Modernization Capability Optimization: Visioning, Strategic Planning, and New Capability Portfolio Management. Top-5 US utility; client confidential. 2014.

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.

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

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

Books

Smart Grid Hype & Reality: A Systems Approach to Maximizing Customer Return on Utility Investment. First edition 327 pages, 2014. Second edition 358 pages, 2018. ISBN 978-0-615-88795-1. Wired Group Publishing.

Noteworthy Publications

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. Republished in the ICER Chronicle, 3rd Edition, March, 2015.

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

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

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

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

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

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

Noteworthy Presentations

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

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

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

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

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

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

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

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

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

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

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

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

Teaching

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

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

Education

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

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

Certifications

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