STATE OF NEW JERSEY
BOARD OF PUBLIC UTILITIES

IN THE MATTER OF THE PETITION OF PUBLIC SERVICE ELECTRIC AND GAS COMPANY FOR APPROVAL OF ITS CLEAN ENERGY FUTURE-ENERGY CLOUD ("CEF-EC") PROGRAM ON A REGULATED BASIS

BPU Docket No. EO18101115
REBUTTAL TESTIMONY
OF

FREDERICK DAUM
EXECUTIVE DIRECTOR – CUSTOMER OPERATIONS

AND

GREGG EDESON
PARTNER – PA CONSULTING

Submitted on Behalf
of
PUBLIC SERVICE ELECTRIC AND GAS COMPANY

October 5, 2020

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<u>BACKGROUND</u>

Q. Would the witnesses testifying on behalf of the Public Service Electric and Gas Company please state their names and professional titles.

A. My name is Frederick ("Fred") Daum and I am employed by Public Service Electric and Gas Company ("PSE&G" or "the Company") as Executive Director, Customer Operations. My professional credentials were provided in Schedule FGD-CEF-EC-1 of my Direct Testimony.

My name is Gregg Edeson and I am a Partner with PA Consulting Group ("PA"). My business address is 501 West 5th Street, Suite 910, Los Angeles, CA 90071. I am testifying on behalf of PSE&G.

Q. Mr. Edeson, what are your responsibilities in your role as Partner at PA Consulting Group?

A. I have been with PA since 1997. PA has over 2,500 consultants globally. We are headquartered in the United Kingdom. Our United States headquarters is in New York City. I am in the Energy and Utilities practice and am responsible for a number of programs and utility client offerings within the practice including but not limited to ReliabilityOne™; iPredict™, our Asset Management offering; Smart Grid inclusive of Advanced Metering Infrastructure ("AMI") initiatives; and benchmarking/best practices across the Customer Service, Transmission, and Distribution utility value chains.

Q. Mr. Edeson, please state your educational background and professional experience.

A. I have worked in the electric utility sector for over 50 years. I worked with Southern California Edison (SCE) prior to the start of my consulting career, which began in 1997. I have an undergraduate degree in Business from the University of Redlands in California and an MBA from Pepperdine University, also in California. I worked across all areas of the Distribution value chain while at SCE including lineman, planning engineer and executive roles over electric operations, planning, construction, customer service, regulatory and labor. Since joining PA Consulting, I have worked with clients in all areas of the utility value chain and disciplines including but not limited to utility operations, planning, reliability and smart grid/AMI implementation. My resume is attached hereto as Schedule GE-CEF-EC-1.

<u>SCOPE OF TESTIMONY</u>

Q. What is the purpose of your rebuttal testimony?

A. We are responding to the direct testimony of Mr. Paul J. Alvarez submitted in this proceeding on behalf of the Division of Rate Counsel ("Rate Counsel") regarding PSE&G's Clean Energy Future - Energy Cloud proposal ("CEF-EC" or "Program"). Our testimony will address a number of false assertions and speculation by Mr. Alvarez. Specifically, we will address (1) Mr. Alvarez's erroneous modifications to the AMI Benefit Costs Analysis ("BCA"); (2) Mr. Alvarez's comments on Use Cases and Benefits of AMI; (3) Mr. Alvarez's unsubstantiated and incorrect claim that PSE&G should have been installing AMI meters in the normal course of business since 2012; and (4) Mr. Alvarez's unsubstantiated and incorrect claim that PSE&G should implement AMI meters now without BPU pre-approval and do so in the normal course of business.

<u>PURPOSE OF BCA AND ALVAREZ'S IMPROPER ADJUSTMENTS</u>

Q. Mr. Alvarez proposes to make adjustments to the BCA methodology submitted by PSE&G for the CEF-EC. Are the adjustments that Mr. Alvarez seeks to make to the BCA appropriate?

A. No. Mr. Alvarez's adjustments reflect a misunderstanding of BCA use and improperly conflate BCA and Revenue Requirement analyses. There is no legitimate basis for any of the adjustments proposed. The BCA as proposed conforms with standard practice, and precedent both in New Jersey and other jurisdictions.

Q. Please clarify the purpose of the BCA in this filing?

A. The BCA has a specific purpose and that is to compare the total incremental costs of an investment with its total incremental benefits to see if the investments provides a net benefit. In the BCA developed for the CEF-EC, $2,054 million in benefits were calculated relative to $785 million in total costs over the 20 year period of the BCA. This yields a net benefit of $1,269 million or $246 million on a present value basis. The BCA is neither designed nor intended to show customer impacts, which has been provided in the bill impact analysis submitted as part of the CEF-EC filing and addressed in detail in the direct testimony of Mr. Stephen Swetz. Nor is the BCA an appropriate tool for addressing concerns about the timing of rate cases and when benefits are passed onto customers.

Q. What adjustments to the CEF-EC BCA has Mr. Alvarez proposed?

A. Mr. Alvarez makes four adjustments to the BCA, none of which reflect common practice. Specifically, Mr. Alvarez seeks to: (1) include undepreciated cost of legacy meters in the BCA; (2) include carrying costs in the BCA; (3) eliminate approximately $350 million of benefits in the period 2024-2028 from the BCA and an additional approximately $75 million thereafter; and (4) exclude any operational benefit not backed by headcount reductions or asset disposal. We will address each of these below.

Q. Is PSE&G's BCA methology consistent with other New Jersey utilities' BCAs for AMI deployment?

A. Yes. The BCA methodology utilized by PSE&G is similar to the approach taken by the Rockland Electric Company ("RECO") in its AMI petition that was deemed satisfactory by the Board in its August 23, 2017 Decision and Order approving that petition.[1] The approach is the same as that of ACE and JCP&L in their recent petitions for approval of AMI.[2]

BCA Stranded Assets Adjustment

Q. One area of difference between BCA methodology submitted by PSE&G and RECO in its AMI filing is the exclusion of stranded costs in the analysis. Why is it appropriate to exclude the cost of legacy meters in the BCA?

A. While stranded asset cost treatment is an important issue, it is a distortion to include in a BCA, the purpose of which is to identify an investment's net incremental value. As explained in PSE&G's response to RCR-E-0013 (c), the CEF-EC should be evaluated on the incremental benefit that it delivers relative to incremental costs associated with its deployment, operation and maintenance.[3] Whether the assets associated with prior investments are partially or fully depreciated at the time of this evaluation should have no bearing on the relative merits of this investment decision. The sunk costs of prior investments have been incurred whether or not

[1] I/M/O the Petition of Rockland Electric Company for Approval of an Advanced Metering Program, BPU Docket No. ER16060524, Decision and Order (N.J.B.P.U. August 23, 2017), available at: https://www.oru.com/_external/orurates/documents/nj/RECOAMIFilingExhibits.pdf?ver=1.0.

[2] I/M/O the Petition of Atlantic City Electric Company for Approval of the Smart Energy Network Program and Cost Recovery Mechanism and Other Related Relief, BPU Docket No. EO20080541 (petition filed Aug. 26, 2020); I/M/O the Petition of Jersey Central Power and Light Company for Approval of an Advanced Metering Infrastructure (AMI) Program (JCP&L AMI), BPU Docket No. EO20080545 (petition filed Aug. 27, 2020).

[3] Schedule-FD-GE-CEF-EC-1.

CEF-EC is implemented. The BCA properly executed by PSE&G demonstrated that implementing the CEF-EC at this point in time will provide a net benefit to customers.

Q. In what way are past meter investment decisions already accounted for in a BCA?

A. Prior metering investment decisions are implicitly factored into the benefits side of the BCA through their impact on the size of the incremental benefit. This was made clear in Massachusetts' utilities grid modernization filings.[4] In that case, prior mass deployment of electric AMR meters had already delivered meter reading cost-savings, thereby limiting the available incremental benefit of implementing AMI. In this way, prior metering investment decisions can impact the Benefits side of a BCA. To also include them on the cost side of the BCA would in effect double count those costs. To do so, as Mr. Alvarez proposes, will provide a false view of the value of this investment.

Q. As part of Mr. Alvarez's adjustments to the BCA, he proposes to include $216 million in stranded asset costs, net of his calculated deferred tax adjustment. Do you agree with this adjustment?

A. No, for the reasons stated above. In addition, the Rebuttal Testimony of Mr. Swetz, submitted herewith on behalf of PSE&G, provides additional detail regarding the flaws of Mr. Alvarez's stranded cost adjustment. In particular, Mr. Swetz explains that retiring existing meters is necessary in order to obtain the benefits of AMI but are not incremental costs to be included in a BCA. The cost of existing meters will be recovered from customers whether the Program is approved (as a regulatory asset) or rejected by the Board (as a real asset). Hence

[4] Petition of Massachusetts Electric Company and Nantucket Electric Company, d/b/a National Grid for Approval by the Department of Public Utilities of its Grid Modernization Plan, et. al, MA D.P.U. 15-120, 15-121, and 15-122, Oder (May 10, 2018) (order approving in part the grid modernization plans filed by Massachusetts Electric Company and Nantucket Electric Company, Fitchburg Gas and Electric Light Company, and NSTAR Electric Cmpany and Western Massachusetts Electric Company), available at: https://www.eversource.com/content/docs/default-source/investors/d-p-u-15-120-15-121-15-122-order-(5-10-18).pdf?sfvrsn=a49fc262_0.

this is not an incremental cost to customers from the Program but a change in the recovery mechanism (amortization of regulatory asset rather than depreciation of a real asset). The purpose of the BCA is to determine if the incremental benefits associated with the installation of AMI justify the incremental costs above a non-AMI meter or if the Company should continue to install non-AMI meters. Therefore, while recovery of stranded costs is a necessary component of the Company's filing, it is not an incremental cost of an AMI meter and should not prejudice the BCA analysis of the benefits and costs of an AMI meter compared to a non-AMI meter.

BCA Carrying Costs Adjustment

Q. Please address Mr. Alvarez's proposal to further adjust the BCA to incorporate an additional $1.1 billion in carrying costs on the programs' $785 million in Capital and O&M costs.

A. Mr. Alvarez is incorrect in recommending this adjustment to the BCA. The adjustment he proposes has no theoretical basis or precedent. As stated above, the purpose of the BCA is to determine if the incremental benefits associated with the installation of AMI justify the incremental costs above a non-AMI meter or if the Company should continue to install non-AMI meters. This is an economic evaluation to determine if investing in AMI is appropriate. A utility must install and operate meters to measure usage and/or demand. Therefore, the BCA is to evaluate the *incremental* benefits of AMI compared to non-AMI meters versus the *incremental* costs of an AMI meter. In the same manner as poles, wires, transformers or any other distruibution asset, the Company will recover the meter costs, including carrying charges, from customers.

Q. Is there any New Jersey precedent supporting Mr. Alvarez's position?

A. Not that we are aware of, and Mr. Alvarez has not provided any support for nor cited any Board orders endorsing his position that Program costs should be artificially increased by the addition of carrying costs in performing a BCA. PSE&G is not aware of any utilities that have included carrying charges in a forward-looking BCA, or any utility commissions that promote their inclusion.

Q. Did the Board require RECO to include carrying charges as an additional customer cost in their AMI program BCA in the manner suggested by Mr. Alvarez?

A. No, it did not. The BCA submitted by RECO did not include carrying charges and the Board's August 23, 2017 Decision and Order approving that petition did not require adjustments to the BCA submitted.[5] The Board specifically stated that "[t]his basic method of [BCA] is adequate for use in reviewing the petition and determining the potential payback and benefits."[6]

Q. Did you ask Mr. Alvarez if he is aware of any commission that has ruled that carrying charges must be included in a BCA?

A. Yes, we did. In response to PS-RC-14(a), Mr. Alvarez stated that he was not aware of any commission that has done so.[7]

Q. Did you ask Mr Alvarez if he is aware of carrying costs being included by any utility in its AMI BCA?

A. Yes, we did. In response to PS-RC-14(b), Mr. Alvarez was unable to provide any examples of utilities that had done so.[8] The three examples he cited (Ameren Illinois, Commonwealth Edeson, and Puget Sound Energy) do not include carrying charges in their BCA calculations

[5] I/M/O the Petition of Rockland Electric Company, supra, n1.
[6] Id. at 21.
[7] Schedule FD-GE-CEF-EC-2.
[8] Schedule FD-GE-CEF-EC-3.

as Mr. Alvarez suggests. Rather each is simply following standard BCA practice of discounting future year costs and benefits to today's dollars (i.e., present value), just as PSE&G has done.[9] In its filing, PSE&G has presented the results of its BCA both in nominal dollars and discounted at a 6.55% allowed rate of return.[10] In both cases, nominal and present value, the benefits substantially outweigh costs of the program.

Q. In response to PS-RC-14 Mr Alvarez sought to tie the rejection of AMI proposals in three states to his testimony that included proposed modifications to utility BCAs to include carrying charges. Is this a reasonable conclusion?

A. No. The AMI proposals were rejected for other reasons, and there is no evidence that Mr. Alvarez's erroneous carrying charges argument was either partly or wholely considered. The Louisville Gas & Electric and Kentucky Utilities' proposal was rejected in large part due to a mismatch between BCA life (23 years) and meter service life (20 years).[11] In Massachussetts, the Department of Public Utilities (MA DPU) did state that benefits were not sufficient to justify the costs but it was not on the basis of carrying charges. Rather, it was due to the BCA's heavy reliance on customer benefits of which the DPU was skeptical given an increase in customers in the relevant service areas opting for competitive suppliers, challenges in benefits tied to the forward capacity market, and AMR saturation.[12] In Viriginia,

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[9] See http://smartenergycc.org/wp-content/uploads/2012/08/Ameren-Ex.-3.1-AIC-AMI-Cost-Benefit-Analysis-Revised.pdf; https://www.smartgrid.gov/files/documents/Advanced_Metering_Infrastructure_AMI_Evaluation_Final_Report_201103.pdf; and Schedule FGD-CEF-EC-2 of PSE&G's CEF-EC filing (PSE&G's AMI BCA).

[10] Please note that the 6.55% discount rate was based on the Company's proposed rate of the return in the 2018 base rate case. If the final approved discount rate of 6.48% was utilized, the BCA net benefit of $246 million on a present value basis would be even greater.

[11] I/M/O Electronic Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for a Certificate of Public Convenience and Necessity for Full Deployment of Advanced Metering Systems, KY PSC Case No. 2018-0005, Order (entered Aug. 20, 2018); available at: https://psc.ky.gov/pscscf/2018%20Cases/2018-00005/20180830_PSC_ORDER.pdf.

[12] Petition of Massachusetts Electric Company and Nantucket Electric Company, d/b/a National Grid, at 133-134, supra n 4.

Dominion's proposal was rejected over concerns of insufficient benefits of the grid hardening program as a whole (not limited to AMI investments), where only a small percentage of customers would benefit from the grid hardening investments included in the first phase of the proposed deployment, and concerns regarding lack of rate design innovation.[13] In short, carrying charges were not identified as pertinent to the commission's decision in any of these cases.

Q. Has Mr. Alvarez had any success with his "carrying costs" adjustments to BCAs that you are aware of?

A. After reviewing the outcomes of cases listed in Mr. Alvarez's CV, we were unable to identify any utility commissions that have agreed with Mr. Alvarez on this point. In fact, in addition to the cases described above, Mr. Alvarez has failed to get his position adopted in cases in front of both the Washington Utilities and Transportation Commission and the Indiana Utility Regulatory Commission. In the Washington case the Commission deferred a final prudency review, without noting any required adjustment to the BCA methodology. In the Indiana case the outcome was approval of the comprehensive grid moderinzation plan (including the AMI investment) without adjustment to the BCA, and a finding that the comprehensive project would provide "a net benefit that exceeds the cost of the eligible improvements whether considered on a nominal or a present value basis."[14]

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[13] Petition of Virginia Electric Power Company for Approval of a Plan for Electric Distribution Grid Transformation Projects Pursuant to § 56-585.1 A 6 of the Code of Virginia, VA SCC Case No. 2018-00100, Final Order (Jan. 17, 2019), available at: https://scc.virginia.gov/docketsearch/DOCS/4dv801!.PDF.

[14] Washington Utilities and Transportation Commission v. Puget Sound Energy, et al., WA UTC Docket Nos. UE-190529, UG 190530, UE190274, UG-190275, UE-171225, UG-171226, UE-190991, and UG-190992 (consolidated), Final Order at 49-50 (July 8, 2020), available at: file:///C:/Users/a00126188/Downloads/UE-190529%20et%20al%20-%20Final%20Order%2008%2005%2003%20-%20Puget%20Sound%20Energy.pdf; Verified Petition of Indianapolis Power & Light Company for Approval of IPL's TDSIC Plan for Eligible Cause No. Transmission, Distribution, and Storage System Improvements Pursuant to Ind. Code § 8-1-39-10, IN URC Cause No. 45264, Order (Mar. 4, 2020), available at: https://iurc.portal.in.gov/docketed-case-details/?id=27ac8d01-32ae-e911-a981-001dd800ba25.

BCA Timing Adjustment

Q. Mr. Alvarez proposes to exclude approximately $350 million dollars in benefits from the BCA because these benefits occur between 2024 and 2028 and an additional approximately $75 therafter. He claims that due to possible timing of future rate cases these benefits should not be counted. Do you agree with this assessment?

A. No. As discussed above, the purpose of the BCA is to identify all costs and benefits that will result from implementation of AMI at PSE&G. The timing of future rate cases and how they reflect the net benefits from AMI is an important issue but is separate from the BCA. To conflate the two is inappropriate. Please refer to rebuttal testimony of Mr Stephen Swetz for additional comment on this issue.

BCA Benefits Headcount Adjustment

Q. Mr. Alvarez proposes an adjustment to the BCA that would eliminate over $135 million in operational benefits not associated with headcount reductions or actual truck reductions. Is this appropriate?

A. No. Mr. Alvarez's contention that over $135 million of CEF-EC operational benefits should be removed from the BCA because they are not associated with headcount or resource reductions is incorrect. Realized operational savings do not require layoffs or headcount reduction. In fact, PSE&G will actively seek to deploy personnel to other tasks that, in the absence of the CEF-EC program, would require the use of contract employees, overtime payments, and new hires. Furthermore, in response to PS-RC-15 Mr. Alvarez admitted that he is not aware of any commission that has ruled that headcount reductions are necessary to a calculation of expense reductions in a cost-benefit analysis. Moreover, he is unaware of any commission that has eliminated entirely from a CBA all reductions in operating expenses that do not have corresponding headcount reductions.[15]

[15] Schedule FD-GE-CEF-EC-4.

a. <u>USE CASES</u>

Q. Mr. Alvarez contends that economic benefits associated with Use Cases in Releases 2-4 should not be considered in the BCA. Do you agree?

A. Yes. The costs and benefits presented in the BCA reflect only those from the 22 Use Cases contained in Release 1. Based on only these Use Cases, the CEF-CE delivers a positive BCA outcome. BCAs for the Release 2 through 4 initiatives have not been conducted and, if necessary, would be the subject of future proceedings to evaluate and approve additional investments required to achieve those future Use Case benefits.

Q. The benefits of Release 2 through 4 Use Cases have not been quantified or included in the BCA. Why is this the case, and why has PSE&G included descriptions in the filing?

A. The potential benefits associated with Use Cases in subsequent releases were included in the filing to illustrate the future possibilities of the Energy Cloud.

Q. Mr. Alvarez points out three additional expected benefits from PSE&G's implementation of the CEF-EC Program that were not included in Release 1. Please address why Conservative Voltage Reduction ("CVR") in particular was included in Release 2.

A. Mr. Alvarez correctly points out that CVR, Peak Time Rebates and third party access to customer energy use data are additional benefits of Energy Cloud implementation. Indeed, PSE&G seeks to implement each of these in subsequent Use Case releases. CVR was included in release two because (1) PSE&G would need to implement remote control and automation of field mounted capacitor banks to effectively implement, and (2) the new Advanced Distribution Management System (ADMS) being implemented as part of PSE&G's Energy Strong 2 program would be required to control the CVR program. The ADMS will not be in service until 2023, and the upgrade of the capacitor communication and control would require additional investment beyond what is included in the filing. Currently PSE&G capacitor banks operate autonomously and without field communication. The lower, and therefore narrower, voltage band would require more monitoring and control to implement and maintain voltage within tariff requirements. PSE&G believes the meter data provided through AMI will provide a detailed voltage and demand curve for circuits to better design and implement a CVR program.

Q. Please address why Peak Time Rebates is included in Release 2.

A. Critical peak pricing, peak time rebates, and Time of Use (TOU) pricing are all mechanisms by which consumers are rewarded for conserving energy during peak demand periods. PSE&G agrees with Mr. Alvarez that these types of mechanisms have the potential to deliver substantial savings to PSE&G customers. PSE&G already has a TOU rate, and will investigate additional rate design opportunities following the implementation of AMI. For this reason, TOU pricing is included among Release 1 Use Cases as a foundational rate option with Critical Peak Pricing including Critical Peak Rebates included as a Release 2 Use Case.

Q. Please address Mr. Alvarez's concern that third party access to customer energy use data is not included in Release 1?

A. Mr. Alvarez notes that Connect-My-Data is a means by which customers can provide authorized third parties with secure and automated access to that data. He argues that Connect-My-Data standard compliance should be included as a Use Case despite the fact that by his own description, Connect-My-Data it is not a Use Case but rather a set of protocols. We would like to point out that Use Cases 1-4, which comprise a set of customer benefiting functions and analytic applications, will indeed employ such protocols, so Mr. Alvarez's concern is misplaced. In addition, the issues raised by Market Participants regarding Third Party Supplier data access are addressed in the Rebuttal Testimony of Mr. Terence Moran, including Rate Counsel's recommendation for incorporation of the Connect-My-Data protocols.

Q. Does PSE&G contend that AMI is a prerequisite for Energy Cloud Releases 2-4?

A. The 48 Use Cases comprising Releases 2 through 4 illustrate potential future applications made possible by implementing the CEF-EC at PSE&G. As Mr. Alvarez points out, some of these Use Cases can be mobilized without AMI. In each of those Use Cases, however, the addition of AMI data and/or communications infrastructure will provide additional functionality and customer benefit. For example, Use Case 2-15, Conservation Voltage Reduction/Optimization can be implemented without meter level data; however, its availability enables more finely tuned optimization of voltage levels, delivering greater grid efficiency and energy savings.

Q. Does PSE&G claim that AMI is a prerequisite for distribution automation, as Mr. Alvarez asserts?

A. No. While related, implementation of and realization of benefits from distribution automation (DA) are not dependent on AMI as proposed in the CEF-EC filing. However, as noted above with respect to Releases 2 through 4, AMI data does enhance the value of DA in many applications by, for example, increasing situational awareness down to the meter level. Deployment of AMI is the key to unlocking additional future benefits set forth in Use Cases 2-4.

Q. Do you agree with Mr. Alvarez's assertion that AMI fails to improve reliability?

A. No. Mr. Alvarez's testimony on this point is both flawed and contradictory. His reliance on recent outages resulting from Tropical Storm Isaias to support his claim that AMI fails to improve reliability is particularly flawed. While he notes that some customers were out of service for more than five days, this data point is unenlightening without a counterfactual scenario in the absence of AMI. It should also be noted that Mr. Alvarez properly identified nested outages and restoration during major events as one area for reliability improvement from AMI, and while he suggests this reliability benefit is "relatively small," he also states in his testimony that "PSE&G's estimate of a 2% SAIDI improvement sounds about right to me."[16]

Q. Mr. Alvarez cites a Newsday report that an unspecified number of PSEG Long Island customers had concerns regarding the recording of energy use during Tropical Storm Isaias as evidence of AMI not providing reliability benefits. Do you wish to address this?

A. Yes. Not only does this reference not support Mr. Alvarez's argument that AMI fails to significantly improve reliability, but he draws incorrect conclusions regarding the misidentification of meters and billing from this reporting. The article notes that during Tropical Storm Isaias, some PSEG Long Island customers noticed that even though their power was out, their MySmartEnergy chart displayed non-zero energy consumption. A subsequent PSEG Long Island customer communication addressed this issue as follows: "When there's an outage, the graph displays estimated usage based on your typical pattern. However, once power is back on, the meter then reports any period of zero usage to MySmartEnergy and, after about 24 hours, corrects the graph. Following Tropical Storm Isaias, this process took longer than usual, but your online usage graph now shows any period of zero usage."[17] The Customer communication goes on to note that a different system is used to produce customer bills. While the utility apologized for the confusion and stated its intent to review the MySmartEnergy tool, the experience at PSEG Long Island in no way supports any of Mr. Alvarez's hypotheses in this current hearing. On the contrary, it highlights how PSEG Long Island customers have come to rely on the AMI-enabled MySmartEnergy tool to view in near real time their energy usage, giving them greater visibility and control. Implementation of the Energy Cloud at

[16] Alvarez at 26-27.
[17] Schedule FD-GE-CEF-EC-5.

PSE&G will similarly provide New Jersey customers greater visibility and control over their energy use.

PRIOR AMI DEPLOYMENT OPTIONS AND METER REPLACEMENT STRATEGY

Q. Please comment on Mr. Alvarez's contention that AMI meter installations had become standard practice by 2012 and hence PSE&G should have been installing AMI meters when older meters failed.

A. Mr. Alvarez bases this assertion on his flawed interpretation of historical meter installation data. While he properly cites the Edison Electric Institute's 2016 estimate that by 2012 approximately 42 million AMI meters had been installed across the US, he provides no evidence that even a small fraction of these AMI meters were deployed in the normal course of business (i.e., as older meters fail). Therefore, while PSE&G agrees that by 2012 many utilities were moving forward with wide scale AMI deployments, Mr. Alvarez's contention that replacing analogue meters with AMI meters at time of failure was standard practice is simply incorrect.

Q. Mr. Alvarez also cited in his testimony PSE&G's installation of gas AMR meters during "routine course of business" as a precedent for his argument. Is this a valid comparison?

A. No. AMR and AMI are wholly distinct technologies with different cost profiles, functionalities and supporting infrastructure. PSE&G's gas AMR deployment only requires a transmitter unit on the gas meter and a receiver carried by a meter reader or Company vehicle. A fully functioning electric AMI system requires much more infrastructure, including telecommunications infrastructure, MDMS, and other systems needed to fully realize the benefits of AMI. This example fails to support his argument.

Q. Mr. Alvarez also suggests the Company should have considered available bridge technologies like upgradeable AMI meters. Mr. Daum, what was PSE&G's experience with bridge AMI meters or what Mr. Alvarez refers to as 'upgradeable' AMI meters?

A. The Company did, in fact, explore using a bridge meter solution; however, the solution was not viable for PSE&G's systems, and therefore, was abandoned. In March 2012 PSE&G procured a trial number of Itron bridge "Open Way" AMI meters. Over a period of several months, PSE&G performed trial testing with these meters only to find that they would not connect to the Company's then current version of Field Collection System ("FCS"). PSE&G worked with Itron to identify and troubleshoot these issues, but possible solutions appeared to add more and more costs as the efforts continued. These efforts ultimately were unsuccessful, and the Company decided to return the initial batch of meters. Again in 2015 after our FCS meter reading system had been upgraded, PSE&G obtained an additional sample set of Itron bridge meters in another attempt to evaluate the technology. This effort was also suspended after further difficulties.

Q. Is there any evidence to suggest that PSE&G's experience with Itron bridge meters reflected a systemic issue with the meters' real-world performance?

A. Yes. In January, 2018, Itron purchased competitor Silver Spring, an alternative to the Open Way solution.[18]

[18]Available at: https://www.itron.com/jp/company/newsroom/2018/01/05/itron-completes-acquisition-of-silver-spring-networks-to-drive-innovation-and-growth-in-iot.

Q. Are there any other reasons why PSE&G did not choose to deploy AMI bridge Meters from 2012?

A. Yes. At the time, AMI technology and bridge meters were not endorsed or advocated by BPU staff and their value was openly questioned by Rate Counsel.[19] Furthermore, the cost for a cellular public network AMI meter in 2009-2010 was on average $385, which far exceeded an analog or AMR meter install.

Q. What would have been the financial and operational results if, despite these concerns, you nevertheless switched to those early AMI meters in the 2011-2012 timeframe or thereafter?

A. For one thing, AMI meters at that time were still maturing and would now be obsolete. Those meters would probably be adding to the stranded costs issue. As for operations, although it is technically possible to install an AMI meter (in stasis) – these meters and communications cards were proprietary and bundled, meaning that you were effectively locking yourself into an AMI vendor and their communications offerings for the life of those meters, effectively guaranteeing these vendor contracts, relying on their future roadmap and removing any negotiation leverage going forward.

Q. Did you ask Mr. Alvarez in discovery to provide examples of other electric utilities that have implemented AMI meters for electric customers in the normal course of business?

A. We did. In response to PS-RC-6 Mr. Alvarez failed to identify any utilities that implemented AMI during normal course of business in the manner and over the timeframe he

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[19] For example, in a December 7, 2012 interview with radio station 9.7wobm that is also posted on the internet, Stephanie Brand on behalf of Rate Counsel was noted as opining that AMI was not worth the investment, and was quoted as stating, "[f]or over a billion dollars [assumed JCP&L and PSE&G cumulative investment] what do we get? We get a meter that will, as it goes out tell the utility that it's going out and then when it comes back on it'll tell the utility that it's coming back on . . . To me, if we have a billion dollars to spend, I'm not sure that's the best way to spend it" available at: https://wobm.com/utilities-have-a-way-of-knowing-when-your-power-is-out-audio/.

argues PSE&G should have known to do.[20] The only utility Mr Alvarez cited was the Hawaiian Electric Company ("HECO"), which in 2019 received *pre-approval* to install AMI meters during normal course of business.[21] This pre-approval was seven years past 2012 and reflects substantial technological maturity from the time that Mr. Alvarez states that this should have been an obvious decision for PSE&G.

Q. In presenting historical meter replacement data in his testimony, Mr. Alvarez has sought to imply that PSE&G has not taken steps that would have reduced AMI roll-out costs. Is this the case?

A. No, it is not. While Mr. Alvarez correctly notes that PSE&G experienced higher electric meter replacement rates in the period 2012-2019 relative to the period 2000-2011, and that PSE&G continues to install non-AMI meters, he is incorrect in concluding that PSE&G has somehow disregarded options that could have reduced stranded asset costs. In fact, the opposite conclusion should be drawn. PSE&G has been active in seeking to reduce stranded meter costs.

Q. Why did PSE&G electric meter replacement rates increase after 2012?

A. Through 2011 PSE&G was replacing electric meters commensurate with depreciation spending. In 2012 PSE&G began replacing plain meters with AMR meters as a course of normal business. At this time PSE&G also allowed customers to request an AMR meter in addition to using AMR meters for safety, hard to access, and chronic no-read accounts. These changes drove up the meter replacements during 2012 through 2014. In 2015 PSE&G increased replacements of obsolete meter models, and a general cleanup of the aging meter

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[20] Schedule FD-GE-CEF-EC-6.

[21] I/M/O the Application of Hawaiian Electric Company, Inc., Hawaii Electric Light Company, Inc., and Maui Electric Company, Limited for Approval to Commit Funds in Excess of $2,500,000 for the Phase 1 Grid Modernization Project, and Related Requests, HI PUC Docket No. 2018-0141, Decision and Order No. 36230 (Mar. 25, 2019), available at: https://www.hawaiianelectric.com/documents/clean_energy_hawaii/grid_modernization/dkt_2018_0141_20190325_order_36230.pdf.

population. This again increased the meter replacements during 2015 through September of 2018. In taking these actions PSE&G sought to ensure high service levels for customers and the accuracy of customer bills, while also minimizing meter costs.

Q. What recent steps has PSE&G taken to reduce stranded meter costs and why did PSE&G continue to install non-AMI meters after October 2018 when it first submitted the Energy Cloud petition?

A. From a peak in 2017, PSE&G has dramatically reduced the number of electric meter exchanges in anticipation of a future AMI deployment. In the fall of 2018, PSE&G first submitted its Energy Cloud filing and subsequently curtailed all electric meter replacements other than essential and required regulatory meter work in order to control stranded meter costs.[22] Meter purchases were restricted, and existing inventory has been allowed to dip below previously-planned volumes for specific applications. Meters removed for regulatory testing are returned to inventory provided that they meet testing criteria. Only minimal purchases are being made to sustain day-to-day operations until a determination is made on the CEF-EC filing.

[22] The Company notes that regulatory replacements for electric meters represent less than half of typical meter replacements in any given year. The Company also notes that during 2020, due to the COVID-19 pandemic response, regulatory replacements have been lower than normal, an unforeseen circumstance that could also lower stranded costs pending approval to implement AMI deployment.

Q. Please address how PSE&G has also sought to reduce the average cost of meters installed since 2018 to reduce stranded meter costs.

A. Late in 2018, the Company was provided a quote of * BEGIN CONFIDENTIAL [redacted] END CONFIDENTIAL* per meter for AMR meters that met the Company's specifications, higher than historical levels in part due to other meter manufacturers ceasing to offer this product. Given the potential for AMI deployment, and the significant cost differential between AMR and solid-state meters (available at a cost of between *BEGIN CONFIDENTIAL [redacted] END CONFIDENTIAL*), PSE&G shifted its meter purchases from AMR to solid state meters at this time, essential stopping AMR purchases. Aside from an opportunistic purchase of a small quantity of AMR meters at a substantial discount, PSE&G has continued this practice of minimizing per-meter costs pending a decision regarding the Energy Cloud filing.

<u>CURRENT AMI DEPLOYMENT OPTIONS</u>

Deployment in Normal Course of Business

Q. AMI meter technology has advanced substantially since 2012. Given these advances, is it now practical to implement AMI meters in the normal course of business?

A. No. Deploying AMI in the normal course of business remains impractical. The Independent Review of RECO's AMI Business Case, and Recommendations for New Jersey Board of Public Utilities, prepared by Navigant Consulting found that a partial, extended or delayed AMI deployment would result in suboptimal benefits and cost inefficiencies.[23] That report noted how a reduction in meters is likely to require a greater number of field devices to ensure a strong mesh communication network, and how a reduction in meter volume would

[23] <u>Independent Review of RECO's AMI Business Case and Recommendations for New Jersey Board of Public Utilities,</u> Capstone Report for: New Jersey Board of Public Utilities submitted by Navigant, A Guidehouse Company (Nov. 6, 2019), <u>available at:</u> https://www.state.nj.us/bpu/pdf/boardorders/2019/20191113/11-13-19-2M.pdf.

have implications for per-meter cost. It also highlighted the fact that an extended AMI deployment would result in a disparity between AMI-enabled services offered to some customer but not others, a disparity highlighted when the cost of meter deployment is factored into the electric rates of all customers.

Q. What will the impact be on the BCA if the deployment timeframe is extended in an attempt to minimize stranded asset value of legacy meters?

A. Extending the length of the deployment period to reflect meter replacement in the normal course of business will greatly dimish the value created for customers from the CEF-EC. It will have a definite negative impact on the BCA, eliminating much if not all of the net benefit of the investment. Doing so will not only result in higher costs of deployment, but will also delay the realization of both customer and operational benefits, currently estimated at $18 million per year starting in 2024 and rising to over $100 million per year within four years.

Q. Mr Alvarez cited HECO's application to the Hawaii PUC for the first phase of a Grid Modernization Strategy. Is this a persuasive and relevant example of a utility deploying smart meters in the normal course of business?

A. The HECO experience is not relevant to this case. In 2018, HECO applied for and was subsequently granted authority to invest over $86 million in advanced meters, a Meter Data Management System ("MDMS") and telecommunications network over a 4 year period (2019-2023).[24] Meters would be deployed to customers enrolling in energy options such as DER and DR programs, and for meter replacements and new construction. While the limited deployment is indicative of a normal course of business implementation, the limited timeframe (4 years) leaves open the possibility of a large scale meter deployment in the near future. It should also be noted that HECO applied and the Hawaii PUC approved this investment under

[24] I/M/O the Application of Hawaiian Electric Company, Inc., supra n 22.

the "lowest reasonable cost analysis" principle, meaning in effect that no attempt was made to quantify the benefits of AMI or understand how these might be reduced by extending the period of deployment.

Q. Are there any other lessons that we can draw from the HECO experience?

A. Yes. Like the vast majority of utilities implementing AMI, HECO sought and was granted pre-approval for its AMI program.[25]*Program Pre-Approval*

Q. Mr. Alvarez argues against pre-approval of the CEF-EC program in his testimony. Is PSE&G's approach in seeking pre-approval consistent with other states' experiences that have implemented AMI already?

A. Yes. In fact, based on a review of 28 utilities that have implemented AMI programs, including HECO, we found that none opted to invest in a non-pilot AMI program without prior board approval.[26] All 28 AMI deployments were undertaken only after receiving pre-approval. While not exhaustive, this peer group includes utilities across different geographies, sizes, and customer densities. Mr. Alvarez's argument that PSE&G should proceed without pre-approval is out of touch with the realities of AMI deployment in New Jersey and across the country.

Q. Does this concluded your testimony?

A. Yes.

[25] I/M/O the Application of Hawaiian Electric Company, Inc., supra n 22.[26]Schedule FD-GE-CEF-EC-7.
[26]Schedule FD-GE-CEF-EC-7.

GREGG EDESON

PARTNER

Gregg Edeson is a recognized leader with over 40+ years in the electric utility industry helping clients to excel in Grid Modernization efforts, asset management & reliability improvement strategies and assuring organizational value from IT/OT investments. He works with senior leadership teams to implement operational improvement initiatives integrated with regulatory and labor strategies.

PRIMARY EXPERTISE

- Smart Grid strategies
- Performance improvement
- Asset management and reliability improvement
- IT/OT strategies and required business process integration efforts, market restructure/governance and strategy.
- ISO Governance and Certification Processes

CLIENTS

- Pepco Holdings Inc./Exelon
- Southern California Edison
- SDG&E
- Puget Sound Energy
- Pacific Gas & Electric
- Portland General
- Comision Federal de Electricidad (CFE)
- ESKOM (South Africa)
- Illinois Power Agency

QUALIFICATIONS

- Juran Institute – Quality Management Certified
- MBA Pepperdine University

EXPERIENCE SUMMARY

- **Grid Modernization Strategies** - helps utilities develop business models and infrastructure initiatives to exploit disruptive technologies with a Grid of the Future.
- **Reliability & Restoration strategies** including resource allocation, design & engineering best practices & capital improvements.
- **Asset Management** – develops risk based, holistic and operationally sound strategies to improve grid performance.
- **IT/OT Systems**– assures people/process & technologies strategies are properly aligned to achieve integration and desired business benefits.
- **Regulatory Strategies –** provides insights to senior management in aligning regulatory and labor strategies to secure rate relief for required capital investments.
- **ISO Governance/Certification –** leads subject matter experts to certify accuracy/validity of ISO tariffs to system application of same as well as oversight and governance

EXPERIENCE

Southern California Edison

Led a team of subject matter experts that developed reliability specific recommendations and initiatives for SCE to achieve Q1 status in 5 years-time. The mitigations and initiatives will realize a 40% improvement in Reliability (SAIDI/SAIFI).

Pepco Holdings

Leading the further deployment of PHI's Smart Grid infrastructure (AMI, etc.), PA developed a prioritized multi-year analytics strategy and roadmap to define and deploy analytics Use Cases, and leverage this investment. PA provided analytics that defined $22 million in savings.

Pepco Holdings

Led a team that provided a comprehensive and repeatable risk-based assessment tool for both transmission and substation critical assets that provided quantitative data for assessing required replacements of said assets.

Pepco Holdings

Pepco initiated a review of existing policies related to DER integration and assigned PA to support the development of a comprehensive DER policy document. PA assessed Pepco's policy hierarchy, aggregated disparate policies related to DER, developed policy for current processes, and facilitated creation of a PHI-level policy for DER integration.

CFE Mexico

Led subject matter expert team to identify and create a roadmap to implement a multi-year performance improvement program including transmission and distribution business units that amounted to 25% operational savings.

Pepco Holdings Inc.

As Partner in Charge, Gregg led a multi-practice team in implementing post-merger operational and Corporate center synergies to set up the new business unit and Shared Services organizations between the newly merged operating companies which identified over $24 million in benefits.

SDG&E and Puget Sound Energy

As Partner in Charge, led teams to improve Customer Service Contact Center operations and quality via training initiatives and quality improvement strategies dealing with handling time, customer interaction consistency, and operational metrics to measure success in an ongoing basis.

South Africa (Eskom and EDI Holdings Inc.) ESKOM

As the Partner in Charge for the National South Africa Electric Utility with over four million customers, Gregg has assisted Eskom on an ongoing basis as a strategic advisor including proposed setting up new ISO type market and governance

Illinois Power Agency (2015)

As Partner helped lead team to review governance and rules of the power procurement structure.

Public Service Electric and Gas Company
Case Name: CEF-EC
Docket No(s): EO18101115

Response to Discovery Request: RCR-E-0013
Date of Response: 5/7/2020
Witness: Daum, Frederick
Stranded Costs of Meters

Question:
Refer to the Company's Petition, Introduction page 15, which estimates that the stranded costs of meters removed to make way for AMI will be $216 million.
a. Did the Company consider deploying AMI over a longer time frame, for example, as the existing meters reached zero book value, to better maximize the value customers would receive from existing meters for which they are paying, and for which they will continue to pay? If not, explain why not.
b. Provide any and all analyses the Company completed to compare the benefits and costs of a graduated AMI roll-out to the benefits and costs of the five-year roll-out the Company is proposing.
c. Indicate where in the Company's benefit-cost analysis (Daum testimony, page 27, Figure 5) the opportunity cost to customers of removing existing meters with remaining book value to make way for AMI meters is recognized. If the Company did not include such costs in its benefit-cost analysis, please explain why not.

Attachments Provided Herewith: 0

Response:

a. Yes, PSE&G did consider deploying AMI over a longer time frame. Slow moving, sporadic, AMI dispersed deployment models are likely to result in poorer performance and an increased network infrastructure equipment and corresponding costs due to meter density not being at levels needed for reliable communications. This can result in more truck rolls to both troubleshoot communication issues and/or install additional network equipment. Only changing meters that reach the end of their useful life has been evaluated. With this approach, it takes more time to create an adequate mesh and does require a more expensive network design. There will be higher labor costs involved if small numbers or areas are changed or if some meters in a multi meter building are changed, but not others. From a customer experience perspective, there would be a great disparity between customers as to when they would fully realize the CEF-EC program benefits. This approach has been seen to introduce confusion with consumers who learn from neighbors at social settings that the neighbor's meter was changed but theirs was not. Selecting a longer deployment period results in other cost drivers, including delayed benefits accrual, since routes with only some AMI meters still require meter reading, collection, and special reading service to remain in place. The positive benefit-cost analysis (BCA) presented in testimony shows that the value associated with full deployment of AMI at this time is materially greater than from the value from persisting with existing meters. This is true irrespective of the book value associated with existing meters. To extend the timeframe for deployment does not create additional value and only reduces and delays the benefits accruing to PSE&G customers.

b. Please see the response to part (a) above.

c. The BCA does not include the remaining book value of AMI meters as a cost. It is not appropriate to do so. The CEF-EC should be evaluated on the benefit that it delivers relative to costs associated with its deployment, operation and maintenance. Whether the assets associated with prior investments are partially or fully depreciated at the time of this evaluation should have no bearing on the relative merits of this particular investment decision.

Data Request: PS-RC-14
Witness: Paul Alvarez

In the Matter of the Petition of Public Service Electric and Gas Company For Approval Of Its Clean Energy Future-Energy Cloud ("CEF-EC") Program On A Regulated Basis

BPU Docket No. EO18101115

PS-RC-14 In his testimony beginning on page 10, line 7, Mr. Alvarez mentions "the carrying charges customers will pay" are "excluded from the PSE&G cost estimate"

(a) Is Mr. Alvarez aware of any commission that has ruled that carrying charges must be included in a Cost Benefit Analysis? If yes, provide copies of those order(s).

(b) Is Mr. Alvarez aware of carrying costs being included by any utility in its AMI Cost Benefit Analysis? If yes, provide copies of such analyses.

Response:

(a): Mr. Alvarez is not aware of any commission that has ruled that carrying charges must be included in a Cost Benefit Analysis. However, Mr. Alvarez notes that several commissions require utilities to estimate the total rate impact of proposed utility investments as part of forward test year ratemaking (including New York, California, and Maryland), or for accelerated cost recovery (riders, Ohio). These requirements incorporate the peak rate impact of such proposals (year 5 of a 5-year deployment, or year 3 of a 3-year deployment, as examples), though not the revenue requirement until assets are fully depreciated. Rate impact estimates include all carrying charges.

In addition, Mr. Alvarez notes that the Ratepayer Impact Measure – a benefit-cost test defined in the California Standard Practice Manual, commonly applied to utility demand-side management programs, and occasionally applied to grid modernization investments – incorporates program revenue requirements (including carrying charges).

Finally, Mr. Alvarez notes that three state utility regulators, once the carrying charge issue was quantified in testimony or presented in a whitepaper he authored, rejected AMI deployment proposals due in large part to insufficient customer benefits relative to customer costs. These include Massachusetts (DPU 15-120, 121, and 122-123); Kentucky (PSC 2016-00370 and 2016-00371); and Virginia (SCC Case No. PUR-2018-00100).

In the Matter of the Petition of Public Service Electric and Gas Company For Approval Of Its Clean Energy Future-Energy Cloud ("CEF-EC") Program On A Regulated Basis

BPU Docket No. EO18101115

(b): Mr. Alvarez is aware of at least three AMI Cost Benefit Analyses which included carrying costs:

i. Ameren Illinois (Attached, see pages 37-38, including sentence "The cost/benefit analysis is taken from the customer perspective, with costs and benefits modeled as revenue requirement adjustments" on page 37, and Table 21 on page 38) [emphasis added]

ii. Commonwealth Edison (Attached, see pages 38-39, including sentence "This view of the net customer impact includes the necessary allowances for taxes paid by ComEd, depreciation, and return requirements" on page 38, and table 9-2 on page 39)

iii. Puget Sound Energy (Attached, see table at the top of page 7, which notes "NPV of project, with revenue requirement")

In the Matter of the Petition of Public Service Electric and Gas Company For Approval Of Its Clean Energy Future-Energy Cloud ("CEF-EC") Program On A Regulated Basis

BPU Docket No. EO18101115

PS-RC-15 In his testimony beginning at page 17, line 10, Mr. Alvarez rejects calculations of benefits that are not based on headcount reductions, i.e., that are based on reductions in levels of effort by calling them "rule of thumb" estimates.

(a) Is Mr. Alvarez aware of any commission that has ruled that headcount reductions are necessary to a calculation of expense reductions in a Cost Benefit Analysis? If yes, provide copies of those order(s).

(b) Is Mr. Alvarez aware of any commission that has eliminated entirely from a CBA all reductions in operating expenses that do not have corresponding "headcount" reductions? If yes, please provide copies of those order(s).

Response:

(a): Mr. Alvarez is not aware of any commission that has ruled that headcount reductions are necessary to a calculation of expense reductions in a cost-benefit analysis.

(b): Mr. Alvarez is not aware of any commission that has eliminated entirely from a CBA all reductions in operating expenses that do not have corresponding headcount reductions.

Schedule FD-GE-CEF-EC-5

View as Web Page

PSEG LONG ISLAND
We make things work for you.

Meter Information During and After an Outage

Customers have asked what happens to electric bills and the energy use data that we display online when there's a power outage. We're happy to provide some answers.

It starts with the electric meter for your account, which offers many benefits, including detailed, daily reports about your energy use. All meters are rigorously checked for accuracy, in both factory testing and our own field-testing.

Online Usage Graph

Within our online My Account services is the *MySmartEnergy* tool, which includes a graph showing your energy use in great detail as reported by the meter. During a power outage, the meter stops reporting usage because there is no usage.

When *MySmartEnergy* does not receive data from the meter, the graph displays estimated usage based on your typical pattern. Once power is back on, the meter then reports any period of zero usage. This new data updates the graph to show zero usage, typically up to 24 hours after an outage.

Following Tropical Storm Isaias, this process took longer than usual, but your online usage graph now shows any period of zero usage.

Accurate Billing

Although you may have seen estimated usage online, we use a different system to produce your bill. The charges on your bill will account for any period when you were not using energy.*

While the online graph does not affect your bill, it did create confusion and for that, we apologize. We are currently reviewing *MySmartEnergy* and will take action to improve your online experience.

PSEG Long Island will always be committed to improving our services and ensuring that you receive accurate bills.

Schedule FD-GE-CEF-EC-5

* If your meter reading day occurs during a power outage, the bill will be estimated. If it was overestimated, the next actual meter reading will always correct this and adjust your charges to ensure that you are only billed for what you actually used.

In the Matter of the Petition of Public Service Electric and Gas Company For Approval Of Its Clean Energy Future-Energy Cloud ("CEF-EC") Program On A Regulated Basis

BPU Docket No. EO18101115

PS-RC-6 At page 14, line 8 Mr. Alvarez uses PSE&G's gas business AMR roll out as an example of a utility installing wireless meter communications over time, in the routine course of business. Please identify and describe any and all examples that Mr. Alvarez is aware of utilities that have rolled out AMI in the normal course of business to electric customers, with all supporting documentation.

Response:

In addition to PSE&G's gas business AMR roll out, Mr. Alvarez is aware that the Hawaii Public Utilities Commission approved an application by the Hawaiian Electric Companies (HEC) to install AMI gradually, in the normal course of business, as dictated by customer participation in various HEC programs. See attached Hawaii PUC Order 36230 in 2018-0141 dated March 25, 2019, page 7, which indicates that the Phase 1 of the HEC deployment will consist of AMI deployment "needed by the programs rates, and tariffs being reviewed and developed in various commission proceedings, including Distributed Energy Resources ("DER"); Community-Based Renewable Energy Program ("CBRE"); Demand Response ("DR"); and Electrification of Transportation ("EoT")."

HEC did not propose a universal (all at once) AMI deployment for all customers as a previous proposal to do so (Hawaii PUC 2016-0087, Order 34281 dated Jan 4, 2017, also attached) was rejected by the Hawaii PUC as too costly relative to benefits, and due to the delayed delivery of AMI benefits to customers (Order 34281, page 41). Mr. Alvarez notes he should have included the Hawaii PUC's rejection of HEC's initial AMI deployment proposal in a list of such rejections he provides on page 50 of his direct testimony.

Review of AMI Implementation Pre-Approvals and Timelines

Holding Co.	Utility	State	Deployment Period	Pre-Approval
AEP	AEP Texas Central	TX	2009-2013	Yes
Ameren	Ameren IL	IL	2014-2019	Yes
Exelon	Baltimore Gas & Electric	MD	2012-2015	Yes
CenterPoint Energy	CenterPoint	TX	2009-2012	Yes
Avangrid	Central Maine	ME	2010-2012	Yes
Cleco Power	Cleco Power	LA	2011-2013	Yes
Exelon	Commonwealth Edison	IL	2015-2019	Yes
Consolidated Edison	Consolidated Edison	NY	2017-2022	Yes
CMS	Consumers Energy	MI	2012-2017	Yes
DTE	DTE Electric Company	MI	2012-2016	Yes
Duke	Duke Energy Indiana	IN	2016-2019	Yes
Duke	Duke Energy Kentucky	KY	2017-2019	Yes
Entergy	Entergy Arkansas	AR	2019-2021	Yes
Entergy	Entergy New Orleans	LA	2019-2021	Yes
NextEra	Florida Power & Light	FL	2009-2013	Yes
Southern Company	Georgia Power	GA	2007-2012	Yes
Green Mountain Power	Green Mountain Power / CVPS	VT	2011-2012	Yes
HEI	Hawaiian Electric Light Co.	HI	2019-2023	Yes
Evergy	KCP&L & Westar	MO	2015-2019	Yes
Consolidated Edison	Rockland Electric (O&R)	NJ	2017-2020	Yes
Exelon	PECO Energy	PA	2012-2014	Yes
FirstEnergy	Pennsylvania Power Co.	PA	2014-2015	Yes
PG&E	Pacific Gas & Electric	CA	2007-2011	Yes
PGE	Portland General Electric	OR	2008-2010	Yes
American Electric Power	Public Service Co. of Oklahoma	OK	2014-2016	Yes
Edison International	Southern California Edeson	CA	2008-2012	Yes
Ameren	Union Electric Co.	MO	2020-2025	Yes
Alliant	Wisconsin Power & Light	WI	2008-2010	Yes