BEFORE THE

DELAWARE PUBLIC SERVICE COMMISSION

PSC Docket No. 13-115

DIRECT TESTIMONY OF

DAVID E. DISMUKES, PH.D.

ON BEHALF OF THE

DIVISION OF THE PUBLIC ADVOCATE

AUGUST 16, 2013

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I. INTRODUCTION

Q. PLEASE STATE YOUR FULL NAME, ADDRESS, AND OCCUPATION.

A. My name is David E. Dismukes. My business address is 5800 One Perkins Place Drive, Suite 5-F, Baton Rouge, Louisiana, 70808. I am a Consulting Economist with the Acadian Consulting Group ("ACG"), a research and consulting firm that specializes in the analysis of regulatory, economic, financial, accounting, statistical, and public policy issues associated with regulated and energy industries. ACG is a Louisiana-registered Limited Liability Company, formed in 1995, and located in Baton Rouge, Louisiana.

Q. DO YOU HOLD ANY ACADEMIC POSITIONS?

A. Yes. I am a full Professor, Associate Executive Director, and Director of Policy Analysis at the Center for Energy Studies, Louisiana State University. I am also an Adjunct Professor in the E. J. Ourso College of Business Administration (Department of Economics), an Adjunct Professor in the School of the Coast and Environment (Department of Environmental Sciences), and a member of the graduate research faculty at LSU. Attachment A provides my academic vitae, which includes a full listing of my publications, presentations, pre-filed expert witness testimony, expert reports, expert legislative testimony, and affidavits.

Q. FOR WHOM ARE YOU APPEARING?

A. I am testifying on behalf of the Delaware Division of the Public Advocate ("DPA").

Q. HAVE YOU PREPARED ANY SCHEDULES IN SUPPORT OF YOUR RECOMMENDATIONS?

A. Yes. I have prepared 18 schedules in support of my direct testimony. Schedule DED-18 attaches all referenced responses of Delmarva to Staff, DPA, and other Intervenor Data Requests.

Q. WERE YOUR TESTIMONY AND SCHEDULES PREPARED BY YOU OR UNDER YOUR DIRECT SUPERVISION AND CONTROL?

A. Yes, they were.

Q. WHAT IS THE SCOPE OF YOUR TESTIMONY IN THIS PROCEEDING?

A. I have been retained by the DPA to provide an expert opinion on economic and policy issues associated with the reliability proposals raised by the Delmarva Power and Light Company ("DPL" or "the Company") that are included in its proposed reliability pro forma adjustment. I have also been asked to opine on the Company's proposed class cost of service study ("CCOSS") and proposed rate design.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. My testimony is organized into the following sections:

- Summary of Recommendations
- Electric Reliability Pro forma Adjustment
- Class Cost of Service Study
- Rate Design

II. SUMMARY OF RECOMMENDATIONS

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE COMPANY'S RELIABILITY PRO FORMA ADJUSTMENT?

A. I recommend that the Commission reject the Company's reliability pro forma Adjustment 26. The investments included in this adjustment are uncertain, and from a policy perspective, not all of the investments are currently "used and useful" or entirely "known and measurable." Moreover, the investments included in Adjustment 26 are not supported by any cost-benefit or value of service studies which should be a pre-requisite for a forward-looking investment adjustment of this nature. The Company is currently exceeding the Commission's reliability standards; therefore, there is no pressing need to include post-test year investments in rate base. The Company's proposal will likely lead to inefficiencies because it removes positive incentives created by regulatory lag. In addition, the Company's past budgeting performance suggests that the budgeted investments included in Adjustment 26 may be overstated by as much as 25 percent or more. Most importantly, the omission of any defined review for appropriateness and reasonableness is a fatal flaw and should serve as a basis for summarily rejecting the Company's proposal.

Q. WOULD YOU PLEASE SUMMARIZE YOUR CCOSS RECOMMENDATIONS?

A. Yes. I recommend that the Commission adopt the Company's proposed CCOSS with the modifications of using a Total Distribution Plant allocator to allocate general and common plant accounts, using 100 percent number of customers to allocate Customer Service and Information Expense Accounts 907 through 910, and 100 percent number of customers to allocate Sales Expense Accounts 912-913.

Q. WOULD YOU PLEASE SUMMARIZE YOUR RATE DESIGN RECOMMENDATIONS?

A. Yes. My rate design recommendations can be summarized as follows:

- Revenue responsibilities for developing rates should be allocated using a two-step methodology. The first step limits the rate increase to any under-earning class, and the second step distributes any remaining revenue deficiency across all other classes in proportion to their test year revenue.

- Existing customer charges should be increased for those classes where their current revenues are less than their customer-related costs to a level that moves towards their full cost of service.
- After developing the customer charges, the remaining costs are recovered through volumetric charges. For those classes that have a Demand Charge and a Delivery Service Rate, I recommend allocating the increase on an equal percentage basis between the demand charge and the delivery rate to maintain the existing relationship between the two components.

III. RELIABILITY PROPOSALS AND ADJUSTMENTS

Q. PLEASE EXPLAIN THE PRO FORMA ADJUSTMENT BEING PROPOSED BY THE COMPANY FOR SAFETY AND RELIABILITY PURPOSES.

A. The Company has requested pro forma Adjustment 26 in order to include in rate base the full estimated cost of proposed reliability enhancing investments that it claims will lead to benefits for all customers.[1]

Q. HOW LARGE ARE THESE PROPOSED RELIABILITY INVESTMENTS?

A. Schedule DED-1 summarizes the Company's request to include in rate base an additional $66.8 million associated with reliability plant closings that are projected to occur from January 2013 to December 2013. The plant closings included in the Company's Adjustment 26 proposal are for investments that, while inclusive of the current calendar year, will be made outside of its proposed test year in this

[1] Michael W. Maxwell, Direct Testimony, 8:13-16.

proceeding.[2] While some of these investment have been made over the course of the current year, others have not, making this adjustment difficult to reconcile with traditional regulatory "known and measurable" standards.

Q. DOES THE COMPANY ATTRIBUTE THE NEED FOR THIS ADJUSTMENT TO WHAT IT SEES AS A REGULATORY LAG PROBLEM?

A. Yes. Delmarva claims that the level of infrastructure investments needed to enhance and maintain system reliability "is far in excess of the book depreciation the Company is recovering in rates."[3] Similarly, the Company notes that it is not realizing sufficient customer and load growth to generate enough additional revenue to offset the costs of the needed reliability investment increase. The regulatory lag created by increased investment requirements and low revenue growth, outside of a rate case, puts the Company in a position where it claims it has been unable to earn a return comparable to other utilities with similar risk.[4]

Q. HAS THE COMPANY PROVIDED ANY ESTIMATES QUANTIFYING THIS REGULATORY LAG CHALLENGE?

A. No. The Company has not provided any detailed earnings attrition analyses that directly links under-earnings with its reliability investment requirements.[5] This is an important omission since an attrition analysis of this nature should be a prerequisite for any post-test year adjustment request. Thus, the Company's post-test year adjustment request is based simply upon broad assertions about what it believes could happen in

[2] Jay C. Ziminsky, Direct Testimony, 27:12-16 and 28:11-14.
[3] Frederick J. Boyle, Direct Testimony, 5:9-12.
[4] Id. at 5:13-22.
[5] Company's Responses to Data Requests AG-REL-36 and AG-REL-37; Frederick J. Boyle, Direct Testimony, 2:21-3:11.

the future, not upon any quantitative analyses specifically estimating the relationship between future earnings and its anticipated reliability investments.

Q. HAS PEPCO HOLDINGS, THE COMPANY'S PARENT, REFERRED TO POST-TEST YEAR INVESTMENT ADJUSTMENTS (LIKE ADJUSTMENT 26) AS A FORM OF REGULATORY LAG MITIGATION?

A. Yes. In a recent presentation to investors, the Company's parent, Pepco Holdings ("PHI"), referred to this post-test year investment adjustment proposal as a method to mitigate against regulatory lag. As recently as the August 7, 2013 Investor Meetings, PHI told its investors that it has requested additional investments to rate base as a "regulatory lag mitigation measure" that would "recover additional reliability plant additions from January 2013 through December 2013 ($10.4 million of revenue)."[6]

Q. WHAT BENEFITS DOES THE COMPANY CLAIM CUSTOMERS WILL RECEIVE AS A RESULT OF ITS RELIABILITY INVESTMENTS?

A. The Company maintains that system reliability is not just good business practice, but that "electric system reliability is a minimum requirement for businesses in evaluating opportunities for economic investment, development and growth."[7] The Company also notes that reliability enhancement will attract new customers to Delaware.[8]

Q. HAS THE COMPANY EXPERIENCED ANY DIFFICULTIES IN MEETING THE COMMISSION'S RELIABILITY STANDARDS OVER THE PAST SEVERAL YEARS?

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[6] Pepco Holdings, Inc., "Second Quarter 2013 Earnings Call," August 7, 2013, p. 8.
[7] Michael Maxwell, Direct Testimony, 8:1-4.
[8] Id. at 8:6.

A. It does not appear to have experienced any difficulties, based on a review of its recent reliability statistics relative to the Commission's reliability standards. Schedule DED-2 shows that the Company has consistently exceeded the System Average Interruption Duration Index ("SAIDI") standard set by the Commission in Docket No. 50, the Electric Service Reliability and Quality Standards proceeding, over the past five years.

Q. HAS THE COMPANY BEEN ABLE TO IDENTIFY THE RELIABILITY INDICES THAT WERE IMPACTED BY PRIOR RELIABILITY INVESTMENTS?

A. No. In response to Staff Data Request PSC-REL-9, Delmarva indicated that it "selects and designs all reliability projects to decrease the frequency and duration of outages on the selected feeders. The requested data surrounding the changes at an individual project level is not available."[9]

Q. HOW DO THE COMPANY'S PROPOSED RELIABILITY INVESTMENT PROJECTIONS COMPARE TO HISTORIC LEVELS?

A. Schedule DED-3 shows that the Company spent a total of approximately $187.7 million for reliability-related capital projects for the years 2008 to 2012. The Company states that its total capital budget for reliability for the years 2013 to 2017 will be $309.1 million, representing an increase of 65 percent over historic trends. Schedule DED-4 provides historic detail for the Company's overall capital budget variance for a six-year period 2007-2012. The schedule shows that the Company has under-spent its capital budget by, on average, 3.5 percent per year. The Company has overspent, however, on reliability projects by close to 5 percent per year, on average, over a comparable time period.

[9] Company's Response to Data Request PSC-REL-9.

Q. ARE THESE CAPITAL BUDGETING VARIANCES LARGE?

A. Yes. The Company's capital budget variance has been, at times, large. For example, Schedule DED-4 shows that in 2007, 2009, and 2012, reliability investments were over-budget by 25.1 percent, 12.1 percent, and 6.7 percent, respectively.

Q. HOW DO THE COMPANY'S RELIABILITY BUDGETS COMPARE TO ACTUAL EXPENDITURES?

A. Schedule DED-5 presents the Company's Reliability Enhancement Project ("REP") budgets compared to actual for the last two years, broken down by Work Breakdown Structure ("WBS") project number. This schedule also shows the projected expenditures for the years 2013 through 2017 at the project level of detail. As depicted, the variances at this level are in many instances significantly different from actual. For example, the Millsboro - Priority Circuit Improvement project, which is part of the current Adjustment 26, was over-budget by 182.5 percent in 2011, and under-budget by 46.8 percent in 2012. Likewise, the Distribution Automation-Christiana Substations project was budgeted at $1.5 million, but the Company expended $3.4 million, an increase of 131 percent.

Q. WERE THERE INSTANCES WHERE 2012 PROJECT BUDGETS WERE UNSPENT AND DEFERRED TO THE 2013 PRO FORMA TEST PERIOD?

A. Yes, there were several reliability projects which fit this criteria. As shown on DED-6, there were 14 REP projects that were 30 percent or more under-budget in 2012, several of which had no funds expended in 2012, yet now are included in the 2013 pro forma test year. Some reliability projects, Millsboro Sub Subscriber – BBW for example, were contained in the budgets for the years 2011 and 2012, but the budgets were never spent. In the current case, the Company's pro forma adjustment includes $145,735 for this reliability project. Similarly, the Company's 2012 reliability budget included $1.0 million for Distribution Automation in the Christiana District; however, only $184,726 was expended in that year. The Company has included $1.5 million in the 2013 reliability budget and Adjustment 26 for this same effort. In total there were 14 reliability projects where a portion of the 2012 proposed project investment was shifted to the 2013 pro forma test period. Adjustment 26 contains $9.4 million related to projects that were deferred from prior years.

Q. HOW LARGE ARE THE COMPANY'S RELIABILITY INVESTMENTS RELATIVE TO ITS OVERALL CAPITAL BUDGET?

A. Schedule DED-3 shows that from 2003 to 2007 reliability investments accounted for 37 percent of the total capital budget. However, this increased significantly to 67 percent of the Company's capital budget for the period between 2008 and 2012. This share of the total anticipated capital budget will increase to 78 percent for the years 2013 to 2017.

Q. HOW DOES THE COMPANY DESCRIBE ADJUSTMENT 26?

A. According to the Company, the investments included in its Adjustment 26 are reliability-related projects that reflect "the continuing improvements that the Company is accomplishing in its reliability program and are provided to customers with the completion of every reliability asset that the Company puts in place."[10]

Q. WHAT TYPES OF PROJECTS ARE INCLUDED IN ADJUSTMENT 26?

A. The projects include the upgrading and improvement of distribution feeders, replacing and upgrading Underground Residential Distribution ("URD") cable

[10] Michael Maxwell, Direct Testimony, 8:14-16.

installations, substation improvements, and the installation of new technology and equipment such as Distribution Automation ("DA") systems.

Q. HAVE YOU PREPARED AN ANALYSIS OF THE COMPANY'S CLOSING TO PLANT FOR THE PROJECTS INCLUDED IN ADJUSTMENT 26?

A. Yes, and this analysis is shown on Schedule DED-7. As shown, for the three months ending March 2013, the Company has not met its forecasted closings on 45 of 95 projects. In addition, the Company estimated that it would have closed $21.0 million of its Adjustment 26 projects to plant in service as of March 2013, but it has closed $18.0 million. Schedule DED-7 also shows that for projects with closings less than forecasted, the amount not closed to plant as of March 2013 was $9.4 million compared to the forecast of $21.0 million.

Q. HAS THE COMPANY PERFORMED ANY COST-BENEFIT STUDIES OR VALUE OF SERVICE STUDIES IN CONNECTION WITH THE INVESTMENTS THAT ARE INCLUDED IN ITS PRO FORMA ADJUSTMENT 26?

A. No. The Company was unable to provide cost-effectiveness, cost-benefit, or value of service studies in connection with the reliability infrastructure investments included in this pro forma adjustment.[11] However, in a subsequent response to Staff discovery, the Company clarified its position by reiterating that although it did not conduct any cost-benefit or value of service studies, it employs a variety of other methods to ensure that investments are developed in an "economic" manner, such as: competitive bidding of materials and use of standard engineering design and work

[11] Company's Responses to Data Requests AG-REL-8 and AG-REL-7.

practices to ensure that the work is accomplished such that it meets all applicable standards.[12]

Q. ARE THESE METHODS THE SAME AS CONDUCTING A COST BENEFIT ANALYSIS?

A No. While the Company may employ a variety of methods to minimize its reliability investment costs, they are not the same as analyzing individual reliability programs for cost effectiveness. As an example, consider a reliability investment that is budgeted at $2 million. Assume that the Company employs a variety of management best practices that not only contains this estimate, but actually reduces the preliminary investment to $1.75 million. If the reliability investment only leads to $500,000 in benefits (say the value of avoided outages), this $250,000 in project development savings ($2 million less $1.75 million) will be irrelevant since the program fails most standard cost-benefit measures: at $1.75 million, the costs of the hypothetical program are still 3.5 times its benefits.

Q. DID THE COMPANY EXPRESS THE OPINION THAT ITS INVESTMENTS COULD NOT BE SUBJECTED TO COST BENEFIT ANALYSIS?

A. Yes. The Company noted that cost-benefit and value of service studies do not lend themselves to these types of investments since

> … the company does not engage in traditional economic analysis of work because the costs, measured in dollars, and the benefits accrued, measured in reliability performance, do not lend themselves to those forms of analysis.[13]

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[12] Company's Response to Data Request PSC-REL-18.
[13] Id.

Q. DO YOU AGREE WITH THE COMPANY'S POSITION REGARDING THE MEASUREMENT OF RELIABILITY INVESTMENT COST-EFFECTIVENESS?

A. No. While it is true that some "qualitative" input can be used in a cost effectiveness analysis, it is not the case that quantitative methods should be summarily dismissed. In fact, Potomac Electric Power Company ("Pepco"), the Company's affiliate in the District of Columbia and Maryland, recently commissioned and filed a cost effectiveness analysis of its proposed selective underground proposals in those jurisdictions. This analysis used results from a 2008 Department of Energy ("DOE") meta-study to evaluate the reduction in outage costs to residential customers as a form of benefit associated with Pepco's selective undergrounding investments. Per unit values of outages were multiplied by estimated outage reductions (i.e., reliability improvements) associated with Pepco's selective undergrounding program. These undergrounding benefits were then compared to undergrounding program costs to develop an estimated net benefit. It is not clear why a similar methodology could not be applied to the Company's proposed reliability programs in Delaware.

Q. DID THE MARYLAND COMMISSION REQUIRE DELMARVA TO FILE A COST EFFECTIVENESS ANALYSIS WITH ANY OF ITS PROPOSED RELIABILITY INVESTMENTS?

A. Yes. The Maryland Commission, in what is referred to as its "Derecho Order," directed each electric distribution utility to file two separate plans with the Commission regarding storm resiliency improvements. First, electric utilities were required to file, on or before May 31, 2013 a plan outlining measures which can be completed in the next five years to accelerate reliability improvements to their distribution systems. Second, utilities are required to file, on or before August 30, 2013, a more detailed, longer-term study that will serve as a platform for further proceedings considering appropriate standards for distribution system resiliency. The Commission explicitly directed the companies to include a cost-benefit analysis for each reliability improvement proposed in their short-term five-year plan filings. The Commission also requested each utility's long-term filings to assess how, and in what locations, their distribution systems would need to be improved in order to restore service following a major storm event to at least 95 percent of its customers within specified time frames. The Commission, in its discussion of the long-term plan filing requirements, reiterated the need for comprehensive cost-benefit analysis weighing the costs of improving the distribution system to different levels of storm resiliency.[14]

Q. DID DELMARVA MAKE A FILING CONSISTENT WITH THE MARYLAND COMMISSION'S DERECHO ORDER?

A. Yes, however, the filing is very general and does not include a comprehensive analysis of the cost-effectiveness of the Company's proposed reliability measures. The Maryland Commission has yet to rule on the completeness of each utility's filings, there is no Maryland Staff report making recommendations on these filings, nor is there any clear road map on how parties will be able to or should respond to these filings. Thus, while the Company may object to the methodological merits of being able to examine cost-effectiveness, that position would appear to be academic and one that PHI is going to need to reconcile very soon with regard to its retail regulators in neighboring jurisdictions.

[14] In the Matter of the Electric Service Interruptions in the State of Maryland due to the June 29, 2012 Derecho Storm, Maryland Public Service Commission, Case No. 9298, Order No. 85385, pp. 3-4.

Q. HAS THE COMPANY EXPLAINED HOW THE REASONABLENESS OF THE FORECASTED RELIABILITY INVESTMENTS IN ADJUSTMENT 26 WILL BE EVALUATED?

A. No. It is unclear how or when any future review of these investments would be undertaken, at least as currently proposed by the Company. If the Commission approves the Company's pro forma adjustment, it could be opining on the propriety of these future investments today, before some of the investments are ever made and determined to be used and useful. The omission of any review for reasonableness and appropriateness is a fatal flaw that in and of itself should serve as a basis for rejecting the Company's pro forma Adjustment 26.

Q. HAS THE COMPANY UNDERTAKEN ANY EVALUATIONS OR ANALYSES FOR THE PURPOSE OF IDENTIFYING PROJECTS THAT WOULD IMPROVE RELIABILITY?

A. Not specifically. In response to discovery on this matter, the Company described its budgeting process, provided a Work Request process used to identify the scope of projects, provided its "Asset Management/Asset Performance Planning and Equipment Condition Assessment" procedures, provided a document entitled "Description of Delmarva Power's Planning Process," and provided a list of approved expenditures. None of these documents contained specific analyses that examined the individual projects included in its pro forma adjustment, and none provided any estimates on how each would contribute to future reliability improvements.[15] Thus, while the Company continually claims that pro forma Adjustment 26 includes forecasted investments to enhance reliability, it has not provided any quantification of

[15] Company's Response to Data Request AG-REL-11.

those reliability benefits in terms of avoided outages or reduced outage minutes. As a result, there is no way that the reliability investments included in pro forma adjustment 26 can be shown to be just and reasonable.

Q. ARE THERE OTHER PROBLEMS WITH THE COMPANY'S POST TEST YEAR FORECASTED PRO FORMA ADJUSTMENT 26?

A. Yes. The proposed reliability investment adjustment removes the regulatory lag and the associated incentives for minimizing over-capitalization. Regulatory lag has long been recognized as a key component of the overall regulatory process given the discipline it can impose on utility operational and investment decisions. Regulatory lag prevents utility regulation from devolving into a "cost-plus" regulatory approach that simply passes through costs on a dollar for dollar basis to ratepayers, and can lead to cost and investment inefficiencies. The cost-plus regulatory approach also shifts a considerable amount of performance-related risk away from utilities and onto ratepayers and leads to inefficient outcomes. This was recognized as early as the 1960s and has come to be known as the "Averch-Johnson" or "A-J" effect.

Q. IF THE COMPANY'S REGULATORY LAG MITIGATION MEASURE (ADJUSTMENT 26) IS ADOPTED, WOULD IT REDUCE THE COMPANY'S RISK?

A. Yes. The Company's proposal is asymmetrical and unfairly tilts the risk scale in its favor. If adopted, it would unfairly shift regulatory, investment, and performance risk away from DPL and onto ratepayers. This result alone should compel the Commission to reject the forecasted investments from the Company's pro forma adjustment. If the Commission decides to accept the Company's proposal, then it should consider an explicit adjustment to the Company's allowed ROE as a compensation to ratepayers, or take the risk-shifting nature of the Company's proposal into account when considering the range of potential ROEs the Commission may select in this proceeding.

Q. PLEASE EXPLAIN HOW REGULATORY RISK IS SHIFTED TO RATEPAYERS.

A. Utilities typically control the timing of rate case filings. Accordingly, utilities enjoy the ability to request higher rates, as well as the protection afforded by a price floor that allows shareholders to retain benefits created by regulatory lag. Thus, in times of over-earning, utilities are not likely to elect to file a rate case so as to keep the gains of regulatory lag for themselves and their shareholders. In times where a utility is under-earning, it can make an application to increase rates. The Company's forecasted investments will exacerbate these timing risks by allowing the Company to increase rates for projected investments that may never be evaluated in the future for reasonableness and appropriateness.

Q. DO YOU AGREE WITH THE SUGGESTION EMBEDDED IN THE COMPANY'S REQUEST THAT PRESUMES REGULATORY LAG IS SOMEHOW BAD AND NEEDS TO BE CORRECTED?

A. No. The presence of regulatory lag in and of itself does not create a policy justification for the Company's forecasted investment adjustment proposal. Regulatory lag can lead to both costs and benefits for a regulated utility. Regulatory lag creates opportunities for utilities to achieve gains as well as losses. The simple fact that regulatory lag creates "opportunities," and not guarantees, is one of the reasons why regulatory lag is considered efficiency-enhancing. There is a long and rich history in the practice and theory of utility regulation supporting these efficiency-enhancing conclusions. Thus, there is no inherent or *a priori* policy rationale for reaching the conclusion that regulatory lag is bad or has a consistently negative implication. If anything, past thought and practice in utility regulation supports rejection of proposals of this nature on a policy basis.

Q. HAVE OTHER COMMISSIONS REJECTED SIMILAR REGULATORY LAG MITIGATION PROPOSALS?

A. Yes. The Maryland Public Service Commission rejected an analogous adjustment requested by Baltimore Gas & Electric Company ("BGE") in its last rate case[16] on the basis that the investments were "not used and useful" or "known and measurable" noting:

> We find that the Company has failed to support its proposal to reflect projected, estimated safety and reliability investments. Not only are these investments not currently used and useful, they are not even known and measurable. While we do not question the Company's good faith to arrive at such an estimate, we note that by the Company's own admission estimates, forecasts and budgets can prove unreliable. In footnote 7 to BGE's Exhibit 13, the Company acknowledged that due to the Derecho storm in 2012 that 'work on planned investments was shifted from non-revenue producing safety and reliability investments to storm restoration.' Thus, even with the best of intentions, budgets and forecasts can prove unreliable. We conclude that it would not be just and reasonable to saddle customers with almost $20 million in additional utility costs based upon estimates that are not fully reliable.[17]

[16] Baltimore Gas & Electric Company; In the Matter of the Application of Baltimore Gas and Electric Company for Adjustments in its Electric and Gas Base Rates, Public Service Commission of Maryland, Case No. 9299. Order Dated February 22, 2013, pp. 20-21.

[17] Baltimore Gas and Electric; In the Matter of the Application of Baltimore Gas and Electric Company for Adjustments in its Electric and Gas Base Rates, Case No. 9299, Order Dated February 22, 2013, p. 37 (Emphasis added).

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE COMPANY'S RELIABILITY ADJUSTMENT 26 PROPOSAL?

A. I recommend that the Commission reject the Company's proposed Adjustment 26. The reliability investments included in this adjustment are uncertain, and from a policy perspective, not all of the investments are currently "used and useful" or entirely "known and measurable." Moreover, the investments included in Adjustment 26 are not supported by any cost-benefit or value of service studies, which should be a prerequisite for a forward-looking investment adjustment of this nature. The Company is currently exceeding the Commission's reliability standards, thus there is no pressing need to include post-test year investments in rate base. The Company's proposal will likely lead to inefficiencies by removing the positive incentives created by regulatory lag. Likewise, the Company's past budgeting performance suggests that the budgeted investments included in Adjustment 26 may be overstated by as much as 25 percent or more. Most importantly, the omission of any defined review for appropriateness and reasonableness is a fatal flaw and should serve as a basis for summarily rejecting the Company's proposal.

Q. DO YOU HAVE AN ALTERNATIVE RECOMMENDATION IF THE COMMISSION DOES NOT ACCEPT YOUR PRIMARY RECOMMENDATION?

A. Yes. I have performed an analysis of the specific projects included in Adjustment 26. Based upon this analysis, at least $39.8 million should be removed from the Company's pro forma adjustment, as the costs have not been justified as described below.

Q. WOULD YOU PLEASE DESCRIBE THE SPECIFIC CONCERNS YOU HAVE ABOUT THE PROJECTS INCLUDED IN PRO FORMA ADJUSTMENT 26?

A. Yes, I found several problems with the proposed projects. These include the inclusion of non-specific blanket projects, projects which were described as "as needed" or "as identified," projects for emergency repairs and restoration, projects associated with spares, and projects not specifically identified as being associated with any reliability improvements. All projects proposed for inclusion in Adjustment 26 are shown on my Schedule DED-8.

Q. WOULD YOU PLEASE DESCRIBE SCHEDULE DED-8?

A. Yes. This schedule contains a list of the Company's reliability projections included in Adjustment 26. The first column contains the WBS, the second column contains a short description of the project, the next column contains a more detailed explanation of the project if it is included in the Reliability Enhancement Plan ("REP"), and the fourth column contains the detailed description for Non-REP projects.

Q. WHAT IS THE DIFFERENCE BETWEEN A REP PROJECT AND A NON-REP PROJECT?

A. The difference between a REP project and a non-REP project was described by the Company as follows:

> The REP is a way to combine the efforts into one program that discuss the commitment that the Company is making to continuously improve its reliability performance. The REP is an integral part of the Company's overall expansion-related efforts. REP work is identified based on the following work criteria, Priority Feeder Upgrades, Underground Residential Distribution Cable Upgrades (URD), Distribution Automation, Feeder Reliability Improvements, Conversions, Substation Reliability

Improvements, Feeder Load Relief. Non-REP projects are comprised of all other work.[18]

Q. ARE THE DESCRIPTIONS OF REP VERSUS NON-REP PROJECTS SIMILAR?

A. Yes, although there is apparently a distinction between the functions they are intended to accomplish. When asked to clarify what "factors and criteria the Company uses to designate which of seemingly similar project types should be considered REP versus non-REP," the Company merely referred to the response to PSC-REL-8, which provides little if any explanation of how similarly-named projects end up in either category. This raises questions as to whether or not projects are moved between categories at management's discretion.

Q. WOULD YOU DESCRIBE THE RELIABILITY PROJECTS INCLUDED IN ADJUSTMENT 26 RELATED TO BLANKET PROJECTS THAT ARE NOT SPECIFICALLY DEFINED?

A. Yes. Schedule DED-8 identifies three projects that are not specifically defined: the Millsboro District Miscellaneous Relay project; the Christiana District Miscellaneous Relay Blanket project; and the Christiana District Substation Planned Improvements. The latter project is described as: "Blanket project – Planned for capital improvements including control house upgrade, roof replacements and cable troughs, etc." The Company described these as blanket work orders that do not have a defined scope. The Company's description further suggests that these projects are intended for very simple miscellaneous relay upgrades that **<u>may</u>** need to be completed. The total amount budgeted for these three projects in 2013 is $206,869. The Commission should not

[18] Company's Response to Data Request PSC-REL-8.

include projects in rate base without a defined scope and which may or may not be completed.

Q. DOES THE COMPANY'S PRO FORMA ADJUSTMENT ALSO INCLUDE COSTS RELATED TO SPARES?

A. Yes. Schedule DED-8 shows that the Company has included $2.3 million associated with Christiana District Spare Distribution Transformers and Millsboro District - PHI Spare Transformers. I disagree with including spare transformers in rate base without additional justification by the Company. The Company has not demonstrated that that the transformers are needed for reliability purposes. I recommend the budgeted amounts for these projects be excluded from Adjustment 26.

Q. WOULD YOU DESCRIBE THE PROJECTS THAT USE THE TERMS "AS NEEDED" OR "AS IDENTIFIED"?

A. Yes. There are two projects which are described as "as needed" or "as identified."

- UDLNRM4CR, Wilmington Network Upgrade, Upgrade the aerial sections of the Wilmington Network by replacing poles, wires and adding distribution transformers as needed.
- UDSNRD8FD Christiana District Distribution Substation Bushing Replacements, Replace bushing sets on transformers, in which the bushings have deteriorated or have not met testing specifications. Recommend replacing Type "U" or as identified by Maintenance testing data. Estimate based on 4 projects per year for 2013-2014, then 3 projects per year 2015-2017.

These two projects classified as "as needed" and "as identified" are not well-defined and certain, nor has it been determined that they have specific known and measurable reliability benefits for ratepayers. Therefore, the Commission should remove $570,713 from pro forma Adjustment 26.

Q. WHAT IS THE NEXT GROUP OF PROJECTS THAT YOU RECOMMEND BE REMOVED FROM PRO FORMA ADJUSTMENT 26 IF THE COMMISSION DOES NOT REMOVE THE ENTIRE ADJUSTMENT?

A. I recommend that the Commission remove projects associated with what appear to be one-time emergency repairs. I disagree with Delmarva's inclusion of these in rate base since they have not been identified as being necessary for improving reliability. Schedule DED-8 shows that there are four projects, totaling $13.7 million of the Company's 2013 budget, which fall within this category:

- UDLBRM3M1, Funds necessary for the emergency restoration of customers;
- UDLNRM3C1, Capital work needed to maintain or restore electric service;
- UDSBRD71D, Millsboro District Emergency Repair/Replacements Distribution Sub Equipment;
- UDSNRD71D, Funds set aside for contingencies across distribution substations in Delaware.

I recommend that the Commission require the Company to demonstrate that these projects will in fact improve system reliability. Absent such a showing, the Commission should reject these projects from inclusion in Adjustment 26.

Q. THE PROJECTS DESCRIBED ABOVE ARE CONSIDERED NON-REP. WHAT IS YOUR RECOMMENDATION CONCERNING THE REMAINING NON-REP

PROJECTS INCLUDED IN ADJUSTMENT 26?

A. I recommend that the remaining projects not included in the REP also be removed from Adjustment 26 since the REP, according to the Company, governs its reliability investment planning. Adjustment 26 includes many investments that are not identified in the Company's REP. The Company has indicated that only those projects included in the REP are related to improving reliability performance.[19] If the Commission determines that some portion of Adjustment 26 should be included in rate base, an additional $22.5 million of Delmarva's proposed adjustment should be removed because the costs are not directly linked with reliability improvements.

Q. CAN YOU SUMMARIZE YOUR ALTERNATIVE RECOMMENDATION?

A. Yes. If the Commission does not accept my primary recommendation to reject the Company's proposed Adjustment 26, then I recommend that the Commission reduce this proposed pro forma adjustment by $39.8 million. This removes from Delmarva's request non-specific blanket projects, projects which have been described as "as needed" or "as identified," projects identified for emergency repairs and restoration, projects associated with spares, and all other projects not specifically part of the REP.

IV. CLASS COST OF SERVICE STUDY

A. INTRODUCTION

Q. WHAT IS THE PURPOSE OF A COST OF SERVICE STUDY?

A. A cost of service study ("CCOSS") is a method by which utility costs and revenues are reconciled across different customer classes. The goal of the study is to determine the cost of providing service to either a particular jurisdiction or a particular customer class, and the revenue contribution each makes to cover those costs. The

[19] Company's Response to Data Request PSC-REL-8.

results of a CCOSS produce a rate of return and revenue requirement that can be used as a tool in developing the revenue responsibility and rates for each rate class.

Q. HOW IS A CCOSS PERFORMED?

A. Typically, a CCOSS is performed in three distinct steps: functionalization; categorization; and allocation. The first step in this process, functionalization, simply defines costs based upon their nature. In the specific case of distribution-only electric utilities, most utility costs are associated with providing distribution services, so most distribution-only electric utility costs are identified or functionalized as distribution-related. The next step of the process "categorizes" each of these respective costs into a particular type of cost, including those that are demand-related, energy-related, or customer-related. The last step of the process "allocates" each of these costs to a respective customer class.

Q. IS THIS A RELATIVELY SIMPLE PROCESS?

A. No. Some costs can be clearly identified and directly assigned to a function or category, while several others are more ambiguous and difficult to assign. The primary challenge in conducting a CCOSS is the treatment of what are known as "joint and common" costs. Given their shared or integrated nature, these joint and common costs can often be difficult to compartmentalize into any particular function or category. Therefore, unique allocation factors are utilized in a CCOSS to classify joint and common costs. The process of developing these cost allocation factors can become subjective and imbued with various interpretations and emphases.

Q. CAN YOU EXPLAIN WHAT YOU MEAN BY DEMAND-RELATED COSTS?

A. Yes. Demand-related costs are associated with meeting maximum electricity demands. Electric substations and line transformers are designed, in part, to meet maximum customer demand requirements. The most common demand allocation factors used in a CCOSS are those related to system coincident peaks ("CP") or non-coincident customer class peaks ("NCP").

Q. HOW ARE ENERGY-RELATED COSTS DEFINED?

A. Energy-related costs are defined as those that tend to change with the amount of electricity sold and can be thought of as volumetric-related costs.

Q. WHAT ABOUT CUSTOMER-RELATED COSTS?

A. Customer-related costs are those associated with connecting customers to the distribution system, metering household or business usage, and performing a variety of other customer support functions.

Q. HOW DO COST OF SERVICE STUDIES RELATE TO COMMONLY QUOTED ECONOMIC PRINCIPLES?

A. CCOSSs are also referred to as "fully allocated cost studies" since they allocate test year revenues, rate base, expenses, and depreciation to various different jurisdictions and customer classes based upon a series of different allocation factors. The purpose of the CCOSS is to estimate the cost responsibility for various jurisdictions and customer classes, which in turn are used to develop rates. At the core of a CCOSS is a set of historic book costs for the Company that has accumulated over decades. Rates are, therefore, based upon historic average costs, whereas economic theory suggests that the most efficient form of pricing in perfectly competitive markets should be based upon marginal costs. However, distribution utilities do not operate in perfectly competitive markets and, by their very nature, are natural monopolies. Thus, reaching the ideal pricing formula outlined in economic theory is impossible since the nature of natural monopolies makes pricing difficult in the presence of declining average costs, coupled with a number of joint and common costs. Added to this problem is the fact that the costs utilized by a CCOSS are historic and static, not dynamic and forward-looking, undermining many experts' cost-causation/pricing claims. There is no one single correct answer that is revealed in a CCOSS, and it is often up to regulators to exercise their appropriate judgment regarding the nature of these costs and the implications they have in setting fair, just, and reasonable rates.

Q. WHAT CONTROVERSIES ARISE IN THE ANALYSIS AND COMPARISON OF VARIOUS CCOSS METHODOLOGIES?

A. The CCOSS process is significantly different than the revenue requirement or cost of capital phase of a typical rate case. While the latter two activities are dedicated to determining how much revenue will be recovered through rates, the CCOSS process determines how those revenues will be recovered, and through which customer rates. The primary controversy with the evaluation of various CCOSS results often rests with determining whether revenues (costs) will be recovered strictly by the peak load contributions of each customer class, or whether the approach will be tempered through the use of peak and off-peak usage considerations. Methodologies that are heavily biased to peak considerations (over non-peak or energy), for instance, can tend to prejudice relatively lower load-factor customers, such as residential and small commercial customers, and prefer larger customer classes and off-peak customers. These approaches also fail to fully capture the basic commodity being sold by the utility which is electricity, and how the value of that commodity varies by the amount purchased by different customer classes.

Q. COULD YOU PLEASE DESCRIBE THE DEMAND ALLOCATORS USED WITHIN THE COMPANY'S CCOSS?

A. Yes. The Company uses three separate allocators to distribute different demand-related costs: Primary Demand ("DEMPRI"), Secondary Demand ("DEMSEC") and Line Transformer Demand ("DEMTRNSF").[20] These three allocators are derived from two separate measurements of electric demand, the first being a Class Maximum Diversified Demand ("Class MDD") and the second being a sum of customer maximum non-coincident demands ("Customer NCP").[21] DEMPRI is derived based on 100 percent Class MDD across all customer classes, while DEMSEC is based on 50 percent Class MDD and 50 percent Customer NCP excluding large secondary, primary, and transmission General Service.[22] Finally, DEMTRNSF is derived using 50 percent Class MDD and 50 percent Customer NCP, while excluding primary and transmission General Service and Class MDD for large secondary General Service.[23]

Q. COULD YOU PLEASE DESCRIBE THE COMPANY'S CLASS MDD MEASURE OF DEMAND?

A. The Class MDD is a traditional measure of non-coincident customer class peaks, or NCP, measured as the maximum hourly system demand attributable to each rate class for a given year, which in this case is the 2011 calendar year.[24] The DEMPRI allocator utilized in the Company's CCOSS is simply the sum of the individual

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[20] Elliott P. Tanos, Direct Testimony, Schedule EPT-1.
[21] Id. at Schedule EPT-1 and 9:21 to 10:9.
[22] Id. at Schedule EPT-1.
[23] Id. at Schedule EPT-1.
[24] Company's Responses to Data Requests PSC-COS-18 and PSC-COS-28.

class MDDs, which in turn is used to allocate Account 361 (Structures & Improvements); Account 362 (Station Equipment); primary voltage system assets of Account 364 (Poles, Towers and Fixtures) and Account 365 (Overhead Conductors and Devices); Account 366 (Underground Conduit); and Account 367 (Underground Conductors and Devices).[25]

Q. COULD YOU PLEASE DESCRIBE THE COMPANY'S CUSTOMER NCP MEASURE OF DEMAND?

A. The Customer NCP measure of demand is an aggregation of each customer's maximum hourly system demand within a rate class.[26] Not all customers possess sufficient metering equipment for the Company to directly measure individual demands, so calculations of the Customer NCP also rely heavily on estimations from a sample of load research meters dispersed throughout the Company's service territory.[27]

Q. HOW IS THE CUSTOMER NCP MEASURE OF DEMAND USED TO ALLOCATE COMPANY COSTS IN ITS CCOSS?

A. As described previously, the Customer NCP measure of demand is combined using a simple average with the Company's Class MDD allocator to create the DEMSEC and DEMTRNSF allocators. However, the DEMSEC allocator excludes Customer NCP and Class MDD measures of demand for large secondary, primary, and transmission General Service customer classes. The DEMTRNSF allocator is similar to the DEMSEC allocator, but includes Customer NCP for large general service customers within its calculations.[28]

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[25] Elliott P. Tanos, Direct Testimony, Schedule EPT-1.
[26] Company's Response to Data Request PSC-COS-29.
[27] Company's Response to Data Request AG-COS-16.
[28] Elliott P. Tanos, Direct Testimony, Schedule EPT-1.

Q. WHICH ACCOUNTS ARE ALLOCATED USING THE DEMSEC AND DEMTRNSF ALLOCATION FACTORS?

A. The DEMSEC allocator is used by the Company to allocate secondary voltage system assets, defined by the Company as secondary voltage assets attached to distribution plant Accounts 364 through 367, and overhead and underground services.[29] The DEMTRNSF allocator is used solely by the Company to allocate distribution plant Account 368 (line transformers).[30]

B. COMPLIANCE WITH ORDER NO. 8011

Q. HAVE YOU REVIEWED THE COMMISSION'S ORDER NO. 8011 ISSUED IN PSC DOCKET NO. 09-414?

A. Yes. Staff found numerous deficiencies with the Company's CCOSS in that proceeding, including: (1) the CCOSS was not updated to include the Company's proposed adjustments to test year data; (2) the Company used Delaware-specific load data for non-residential classes, but PEPCO-Maryland average load factors for residential customers; (3) the Company used a 1996 system loss study to develop demand and energy allocators; (4) the Company did not use weather-normalized data; (5) the Company failed to update the CCOSS for certain post-filing corrections; (6) the Company used a different overall rate of return from what the Company was proposing; and (7) the Company allocated service facilities to customers using demand-related allocators rather than customer-related allocators.[31] The Settlement Agreement approved in that proceeding included a provision to convene a CCOSS workshop for

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[29] Id. at Schedule EPT-1.
[30] Id. at Schedule EPT-1.
[31] In the Matter of the Application of Delmarva Power & Light Company for an Increase in Electric Base Rates and Miscellaneous Tariff Changes (Filed September 18, 2009), Delaware PSC, Docket No. 09-414, Order No. 8011, ¶ 314.

purposes of developing an agreement on CCOSS approaches to be used in future rate cases.[32]

Q. DID THE COMPANY CONVENE THE AGREED TO CCOSS WORKSHOP?

A. Yes. The workshop was held on August 24, 2011, at the Commission offices in Dover.[33] According to the event agenda, the workshop covered issues associated with obtaining load data for Delaware residential customers, weather normalization, system losses analysis, allocation of customer-related services, geographic information system ("GIS") uses to functionalize system plant assets, and other related matters.[34]

Q. HAS THE COMPANY MODIFIED ITS CCOSS PRACTICES IN WAKE OF THE AUGUST 24, 2011, WORKSHOP?

A. Yes. The Company notes that it has made five separate changes to its CCOSS practices in wake of the August 24, 2011 workshop that include:

1. The use of Delaware-specific load survey data to estimate residential non-coincident peak demands.
2. The use of weather normalized sales and revenue data within the CCOSS.
3. Utilization of an updated analysis of system losses within the CCOSS.
4. Account 369 – Service Lines are now allocated on the basis of a derived allocator.
5. Traffic signal service customers are now disaggregated from the general street lighting class in the CCOSS.[35]

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[32] Id. at 316.
[33] Elliot P. Tanos, Direct Testimony, 7:22-23.
[34] Company's Response to Data Request PSC-COS-22.
[35] Id.

Q. HAVE YOU REVIEWED THE COMPANY'S LOAD SURVEY METHODOLOGY?

A. Yes. The Company provided information regarding its load research activities that includes electronic printouts of software programming code and its estimated statistical parameters.[36] The analyses show that the Company used Delaware-exclusive load data for the 12 months ending 2011 in determining both Class MDD and Customer NCP measures of demand usage.[37]

Q. HAVE YOU REVIEWED THE COMPANY'S WEATHER NORMALIZED SALES AND REVENUE DATA USED IN THE CCOSS?

A. Yes. The Company weather-normalized test year 2012 sales and revenue data associated with the residential and commercial portions of sub-transmission general service rate classes. The overall effect of the Company's weather-normalization varies by rate class, but results in a total upward revenue adjustment in the CCOSS model of 0.22 percent.[38]

Q. HAVE YOU REVIEWED THE COMPANY'S UPDATED ANALYSIS OF SYSTEM LOSSES?

A. Yes. The Company hired Management Application Consulting, Inc. ("MAC") to perform an analysis of system losses for the 2011 calendar year. This report was finalized by MAC in February of 2013 and provided through discovery to parties for review in this proceeding.[39]

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[36] Company's Response to Data Request PSC-COS-18.
[37] Id.
[38] Company's Response to Data Request AG-GEN-10.
[39] Company's Response to Data Request PSC-COS-18.

Q. HAVE YOU REVIEWED THE COMPANY'S METHODOLOGY FOR ALLOCATING ACCOUNT 369?

A. Yes. The Company conducted an accounting cost study which estimated the average cost per customer receiving service through overhead and underground secondary service lines.[40] The Company's revised Account 369 allocator allocates slightly more costs to residential customers (91.9 versus 87.6 percent) than an allocator based solely on total number of customers receiving service at secondary voltage levels. Monetarily, this results in an allocation change to the Company's total distribution plant of slightly more than $3.7 million relative to a total distribution plant value of nearly $974 million.[41]

Q. HAS THE COMPANY DISAGGREGATED THE TRAFFIC SIGNAL AND GENERIC STREET LIGHTING SERVICE CLASSES IN ITS CCOSS?

A. Yes; however, summary results presented by the Company and in my supporting schedules still aggregate these services within the street lighting service class. The traffic signal class only accounts for slightly more than 1.0 percent of street lighting service revenues, or 2.1 percent of allocated operating expenses, to the street lighting service customer class. The difference in the relative rate of returns for these two services also differs by only 0.17 under the Company's proposed allocations.[42]

Q. HAS THE COMPANY COMPLIED WITH THE SETTLEMENT AGREEMENT IN PSC DOCKET NO. 09-414?

A. Yes; however, there are still deficiencies in the Company's COS methodology. For example, load data used in the Company's CCOSS is based on usage for the 12

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[40] Company's Response to Data Request PSC-COS-18.
[41] Elliott P. Tanos, Direct Testimony, Schedule EPT-1.
[42] Id.

months ending 2011, a full year prior to the test year.[43] Furthermore, information provided by the Company shows that it has not verified the validity of its load research samples since an analysis was conducted in April 2008 using September 2007 billing data.[44] When asked to provide internal documents regarding the Company's policy for updating load research samplings, the Company stated, "Delmarva has no written policy on sample renewal but relies on the quality of current sample load data statistics to dictate sample maintenance needs."[45]

C. ALTERNATIVE CCOSS AND RECOMMENDATIONS

Q. DO YOU DISAGREE WITH ANY OF THE ASSUMPTIONS OR ALLOCATION FACTORS INCORPORATED IN THE COMPANY'S PROPOSED CCOSS?

A. Yes. I disagree with two allocation factors used by the Company in its CCOSS: (1) the Company's use of a labor allocator to allocate general and common plant accounts and (2) the Company's use of an allocator derived from a 50 percent weight on number of customers and 50 percent energy sales to allocate Accounts 907 through 913.

Q. HAVE YOU PREPARED AN EXHIBIT THAT COMPARES THE COMPANY'S ALLOCATION FACTORS TO THE ONES YOU ARE RECOMMENDING?

A. Yes. Schedule DED-9 compares my proposed allocation factors to the Company's for the CCOSS. The first column in the schedule lists the account name, and the second and third columns compare the Company's proposed allocation method with my recommendations.

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[43] Company's Response to Data Request PSC-COS-18.
[44] Company's Response to Data Request AG-COS-19.
[45] Company's Response to Data Request AG-COS-25.

1. GENERAL AND COMMON PLANT ACCOUNTS

Q. PLEASE EXPLAIN HOW GENERAL AND COMMON PLANT ACCOUNTS ARE TYPICALLY ALLOCATED.

A. As stated previously, all CCOSS and rate design analyses incorporate a degree of subjectivity, with often more than one method being a valid allocation method. There are three accepted methods for allocating general and common plant accounts. These are discussed in the Electric Utility Cost Allocation Manual published by the National Association of Regulatory Utility Commissioners ("NARUC," generally "NARUC Manual"). The first is on the basis of overall total plant (or in this case total distribution plant). This method is supported by the theory that general plant supports the other operations of the utility, such as the distribution of electric power. The second commonly-accepted allocation methodology is to allocate general and common plant on the basis of square footage of office space designated to each function of the utility's operations (i.e. distribution and customer accounting and information). The third commonly-accepted method of allocating general and common plant is on the basis of operating labor ratios.[46]

Q. IS THE COMPANY'S USE OF A LABOR ALLOCATOR TO ALLOCATE GENERAL AND COMMON PLANT CONSISTENT WITH THE THREE ACCEPTED ALLOCATION METHODS YOU LIST?

A. Yes. The Company's labor allocator is similar in function to the use of operating labor ratios discussed in the NARUC Manual. However, the NARUC Manual is not

[46] National Association of Regulatory Utility Commissioners, Electric Utility Cost Allocation Manual, January 1992, p. 105.

intended to be prescriptive, as the preface section of the manual clearly states.[47] I do not agree with the use of such an allocator given the unnecessary complexity this approach adds to the CCOSS, particularly when there is a more straight-forward allocation method like my recommended use of a total distribution plant allocator.

2. CUSTOMER SERVICE, INFORMATION, AND SALES EXPENSES

Q. PLEASE EXPLAIN THE COMPANY'S ALLOCATION OF COSTS ASSOCIATED WITH CUSTOMER SERVICE AND INFORMATION EXPENSES (ACCOUNTS 907 – 910) AND SALES EXPENSES (ACCOUNT 913).

A. The Company utilizes two allocators, CSERV and CSALES,[48] to distribute all Customer Service, Information, and Sales Expenses listed as Accounts 907 through 913. These two allocators are identical in every respect and are calculated by giving 50 percent weight to total number of customers and 50 percent weight to total energy sales.[49]

Q. DO YOU AGREE WITH THIS ALLOCATION METHOD?

A. No. As stated previously, all CCOSS and rate design analyses incorporate a degree of subjectivity, with often more than one method being a valid allocation method. However, it is widely accepted that these expenses are customer-related. Customer service and information expenses (Accounts 906 through 910) include costs associated with encouraging safe and efficient use of the utility's service and responding to customer inquiries.[50] Sales Expenses (Account 911 through 917) are

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[47] Id. at p. ii.
[48] Although the factor names are different, the actual allocation factors are the same for metric.
[49] Elliott P. Tanos, Direct Testimony, Schedule EPT-1.
[50] National Association of Regulatory Utility Commissioners, Electric Utility Cost Allocation Manual, January 1992, p. 103.

costs associated with the advertising of utility services to influence customers.[51] Intuitively, these costs are more associated with the number of customers on the utility's system than the total amount of energy sold to end-use customers.

Q. WHAT DOES THE NARUC MANUAL SAY ABOUT THESE CUSTOMER-RELATED EXPENSES?

A. While the NARUC Manual is admittedly not prescriptive, it does offer some rather definitive guidelines on the allocation of these types of costs by noting that:

> The usual approach in functionalizing customer accounts, customer service and the expense of information and sales is to assign these expenses to the distribution function and classify them as customer-related.
>
> ...
>
> Where these accounts have been assigned to the distribution function and classified as customer-related, care must be taken in developing the proper allocators. Even with detailed records, cost directly assigned to the various customer classes may be very cumbersome and time consuming. Therefore, an allocation factor based upon the number of customers or the number of meters may be appropriate if weighting factors are applied to reflect differences in the cost of reading residential, commercial, and industrial meters.[52]

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE ALLOCATION OF CUSTOMER SERVICE, INFORMATION, AND SALES EXPENSES (ACCOUNTS 906 THROUGH 917)?

A. I recommend the Commission adopt a customer-based allocation factor given the nature of the costs and the fact that the use of a customer-based allocation factor for these costs is generally more consistent with traditional cost of service modeling.

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[51] Id. at pp. 103-104.
[52] Id. at pp. 102-103.

D. CCOSS RECOMMENDATIONS

Q. DO YOUR CCOSS RECOMMENDATIONS CHANGE THE CLASS RATES OF RETURN?

A. Yes. I have identified those changed class rates of return and compared them to the Company's original CCOSS results in Schedule DED-10. I have also prepared an alternative CCOSS using my recommended allocation factors, which is attached to this direct testimony as Schedule DED-11. For comparison purposes, results of the Company's CCOSS are additionally shown within Schedule DED-12.

Q. WOULD YOU PLEASE SUMMARIZE YOUR CCOSS RECOMMENDATIONS?

A. Yes. I recommend that the Commission adopt the Company's proposed CCOSS with the modifications of using a Total Distribution Plant allocator to allocate general and common plant accounts, using a 100 percent number of customers to allocate Customer Service and Information Expense (Accounts 907 through 910), and using a 100 percent number of customers to allocate Sales Expense (Accounts 912 and 913).

IV. RATE DESIGN

A. RATE DESIGN OBJECTIVES

Q. WHAT ARE SOME OF THE GUIDING CRITERIA OR PRINCIPLES UPON WHICH RATE DESIGN SHOULD BE BASED?

A. There are several generally-accepted rate design principles used in utility regulation that include:

- Rates should be fair, just, and reasonable, and not unduly discriminatory.

- To the extent possible, gradualism should be used to protect customers from rate shock.
- Rate continuity should be maintained.
- Rates should be informed by costs, but class cost of service results need not be the only factor used in rate development.
- Rates should be understandable to customers.

Q. HOW ARE THE ABOVE CRITERIA BLENDED TO DEVELOP RATES FOR A REGULATED UTILITY?

A. While it is important to consider all of the earlier-mentioned principles, any principle's relative weight can change depending upon the importance of certain policy goals. Rate design should strike a balance between policy goals and result in rates that are fair, just, and reasonable. Because there is no pre-set universally-accepted formula for developing rates, judgment is often necessary in formulating a rate design that meets these objectives.

Q. HAS THE COMMISSION COME TO SIMILAR RATE DESIGN CONCLUSIONS?

A. Yes. In designing rates in Delmarva's 2005 rate case, the Commission emphasized gradualism because customers were "to experience substantial rate shock as a result of the implementation of supply rates" at the same time new base rates were to go into effect.[53]

Q. HAVE YOU REVIEWED THE COMMISSION'S ORDERS IN THE LAST THREE DELMARVA RATE CASES?

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[53] In the Matter of the Application of Delmarva Power & Light Company for Approval of a Change in Electric Distribution Base Rates and Miscellaneous Tariff Changes (Filed September 1, 2005), Docket No. 05-304, Order No. 6930 (September 1, 2005) at p. 145.

A. Yes. The Company's last three rate cases date back to 2005 and include Docket No. 05-304 (2005), Docket No. 09-414 (2009), and Docket No. 11-528 (2011).

Q. CAN YOU EXPLAIN THE COMMISSION'S RATE DESIGN AND REVENUE DISTRIBUTION FINDINGS IN THE LAST TWO RATE CASES?

A. Yes. The Company's two most recent rate cases were settled by stipulation. In both cases, the Commission approved a stipulation among the parties that resulted in the distribution of the approved revenue increase to all classes except the Transportation class on an equal percentage basis.[54]

Q. WHAT REVENUE DISTRIBUTION METHODOLOGY WAS APPROVED BY THE COMMISSION IN DELMARVA'S 2005 RATE CASE?

A. In the Company's 2005 rate case (Docket No. 05-304), the Commission approved Staff's revenue distribution methodology, which allocated the approved revenue decrease in two steps. First, specific class revenue goals were determined for the classes targeted to receive rate increases to move them closer to their required class returns. Second, the remaining classes received decreases and these were determined by "scaling back Delmarva's claimed cost-based class revenue requirements for those service classifications proportionately to derive Staff's recommended base rate reduction."[55]

Q. HOW WERE THE RATES DESIGNED IN THE COMPANY'S LAST THREE RATE CASES?

[54] In the Matter of the Application of Delmarva Power & Light Company for an Increase in Electric Base Rates and Miscellaneous Tariff Changes (Filed September 18, 2009), Docket No. 09-414, Order No. 7897 (January 18, 2011) at Exhibit A, pp. 4-5; In the Matter of the Application of Delmarva Power & Light Company for an Increase in Electric Base Rates and Miscellaneous Tariff Changes (Filed December 2, 2011), Docket No. 11-528, Order No. 8265 (December 18, 2012) at p. 30.

[55] Delmarva Power, Docket No. 05-304, Order No. 6930, supra at pp. 138-139.

A. There is no discussion on how rates were designed in the settlement agreements in the last two rate cases (Docket Nos. 09-414 and 11-528). However, the Commission adopted Staff's rate design proposal in Delmarva's 2005 rate case (Docket No. 05-304). Customer charges were set at a level halfway between a customer's current customer charge and Delmarva's proposed customer charge in order "to move the customer charges toward cost of service while simultaneously limiting the intra-class rate impacts that would otherwise result from Delmarva's proposed rate design."[56] For classes with demand charges, the residual revenue class revenue requirement was assigned to the demand charges in a constrained manner so that no class' demand charge would be increased. Any remaining revenue requirement was assigned to the energy charges.

Q. TURNING TO THE CASE AT HAND, CAN YOU SUMMARIZE THE COMPANY'S RATE DESIGN GOALS?

A. Yes. The Company's primary guiding principle to support its rate design is cost causation. The Company's position is that rates that accurately reflect underlying costs provide a greater degree of fairness.[57] Delmarva uses class relative rates of return to evaluate the degree to which its rate design accurately reflects underlying costs.[58] In considering the amount of revenue to allocate to a class, the Company states it takes into consideration customer impacts:

> Movement of all service classificationURORs [Unitized Rates of Return] to 1.0 in a single rate change may require significant shifts in allocation of revenue requirements between service classifications and, consequently, could have large inter-class rate impacts. Therefore, customer impact

[56] Delmarva Power, Docket No. 05-304, Order No. 6930, supra at p. 139.
[57] Marlene C. Santacecilia, Direct Testimony, 2:23 and 3:1-4.
[58] Id. at 3:7-15.

should be considered as a balancing factor in any effort to achieve the goal of setting all service classification URORs at unity.[59]

B. REVENUE DISTRIBUTION

Q. PLEASE DISCUSS THE COMPANY'S PROPOSED REVENUE DISTRIBUTION.

A. The Company follows a two-step process. In the first step, the Company's goal is to move each class rate of return toward or within a "reasonable band" (0.90 to 1.10) of the overall system of average rate of return.[60] In the second step, the remaining revenue increase is allocated to all rate classes equally[61] based on their current distribution revenue as a percent of the total distribution revenue.[62] The Company limits the increase of any one service classification to 1.5 times the overall percentage increase.[63]

Q. CAN YOU PLEASE EXPLAIN WHAT YOU MEAN BY A RELATIVE RATE OF RETURN?

A. Yes. A "relative rate of return" is simply the ratio of a given class' estimated rate of return to the overall system rate of return. For example, if the residential class is estimated to be earning 11 percent from the CCOSS, and the Company is requesting a 10 percent overall rate of return, then the residential class can be said to have a "relative rate of return" of 1.10 (i.e., 11 percent divided by 10 percent). Relative rates of return can also be thought of as a special type of index number measuring a specific class' return relative to the Company's overall rate of return. Thus, a class with a

[59] Id. at 3:20-23 and 4:1-2.
[60] Id. at 4:5-7.
[61] Id. at 4:7-8.
[62] Company's Response to Data Request AG-RD-25.
[63] Marlene C. Santacecilia, Direct Testimony, 4:8-10.

relative rate of return greater than 1.0 means that the class is estimated to be earning at a percent greater than the Company's overall rate of return, and one with a relative return below 1.0 can be said to be earning an amount less than the Company's overall rate of return. Schedule DED-10 presents the Company's estimated class relative rates of return under its current and proposed rates.

Q. WOULD YOU PLEASE SUMMARIZE HOW THE COMPANY'S REVENUE INCREASE WAS DISTRIBUTED IN ITS LAST THREE RATE CASES?

A. The last two rate cases (Docket Nos. 11-528 and 09-414) ended in settlement whereby the authorized revenue increase was distributed on an across-the-board basis, i.e., the percentage change in distribution revenues was the same for each class, except class General Service Transmission (GS-T), which did not receive any of the increase.[64] In the preceding case (05-304), the Commission approved the Hearing Examiner's finding that the Staff's allocation methodology should be adopted over the Company's proposal for several reasons.[65] First, Staff placed more emphasis on gradualism than the Company because a large supply-side rate increase was taking place concurrently with the culmination of the rate case. The Hearing Examiner in that proceeding found it appropriate to avoid rate shock.[66] Second, Staff's methodology did not result in situations where customers within a class were proposed to receive a rate increase when the class as a whole received a rate decrease.[67]

Q. WHAT IS THE IMPACT ON THE RESIDENTIAL CLASS WITH THE COMPANY'S PROPOSED REVENUE DISTRIBUTION?

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[64] Delmarva Power, Docket No. 11-528, Order No. 8265, supra, at p. 30.
[65] Delmarva Power, Docket No. 05-304, Order No. 6930, supra at ¶298.
[66] Id. at ¶287.
[67] Id. at ¶290.

A. The Company's revenue distribution proposal results in an increase in rates of 21 percent for Residential and almost 35 percent for Residential Space Heating.[68] The Company's revenue distribution proposal results in allocating almost 65 percent of the revenue requirement to the residential classes.

Q. WHAT ARE YOUR REVENUE DISTRIBUTION RECOMMENDATIONS?

A. I recommend a two-step revenue distribution that limits the rate increase to any under-earning class in the first step and distributes any remaining revenue deficiency across all other classes in proportion to their test year revenue in the second step. My approach is consistent with the settlement approved in the last rate case, which consisted of a two-step approach, and with the overall allocation of the proposed rate increase to under-earning classes. My proposed increase to these under-earning classes is tempered, however, by allocating some share of the proposed rate increase to the over-earning classes. The results of my recommended revenue distribution are shown on Schedule DED-13.

C. CUSTOMER CHARGES

Q. HOW DO THE COMPANY'S RESIDENTIAL CUSTOMER CHARGE REVENUES COMPARE WITH THE RESULTS OF ITS CLASS COST OF SERVICE STUDY?

A. The customer charge revenue associated with the Residential class, including Residential-Time of Use customers, has been provided, along with customer charge revenue recoveries for the other customer classes, in Schedule DED-14.

Q. WOULD YOU PLEASE DISCUSS THE COMPANY'S CUSTOMER CHARGE PROPOSALS?

[68] Marlene C. Santacecilia, Direct Testimony, Schedule (MCS)-1.

A. Yes. A summary of the Company's current and proposed customer charges has been provided in Schedule DED-15. The Company is proposing to maintain its current rate structure with a delivery charge and a customer charge. The proposed customer charges were determined by moving current charges towards the level of customer-related costs, with a limitation of a 50 percent increase.[69]

Q. WHAT IS THE IMPACT OF THE COMPANY'S RECOMMENDATION ON THE RESIDENTIAL CLASSES?

A. The Company proposes to increase the customer charge for the Residential and Residential Space Heating classes by close to 50 percent, and the Residential-Time of Use class by 42 percent. The Company proposes to increase customer charges for the Small General Service by 18 percent. The customer charge increases for the remaining classes range from no change for the Large General Service-Secondary class to 101 percent for the General Service Primary class.

Q. HOW DO THE COMPANY'S PROPOSED RESIDENTIAL CUSTOMER CHARGES COMPARE TO OTHER ELECTRIC DISTRIBUTION COMPANIES?

A. Schedule DED-16 provides a survey of current residential and small commercial customer charges for major electric distribution companies operating in the Atlantic region.[70] The Company's proposed Residential customer charge of $13.98 per month is higher than the average residential system charge of $9.33 for the surveyed Atlantic region utilities. Six electric distribution utilities in the survey have residential customer charges greater than the Company's proposal, and 16 companies have a customer

[69] Company's Response to Data Request AG-RD-44.

[70] The Atlantic region includes New York, Pennsylvania, New Jersey, Maryland, Delaware, District of Columbia, West Virginia, North Carolina, South Carolina, Virginia, Georgia, and Florida as defined by the U.S. Census Bureau.

charge less than the Company's proposal. Delmarva's proposed residential system charge is higher than 73 percent of the utility companies included in the survey.

Q. WHAT ABOUT THE SMALL COMMERCIAL CUSTOMER CHARGES?

A. The Company's proposed small commercial customer charge of $12.54 per month is lower than the average small commercial customer charge of $13.82 for other regional utilities. Twelve out of 22 electric distribution companies (55 percent) in the survey referenced earlier have customer charges lower than the Company.

Q. HOW SHOULD POLICY BALANCE RATE DESIGN GOALS BETWEEN SETTING APPROPRIATE CUSTOMER CHARGES AND VOLUMETRIC RATES?

A. Modern utility pricing theory is primarily concerned with the development of optimal tariff design, which over the years has become dominated by a form of pricing referred to as a "two-part tariff," sometimes referred to more technically as a non-linear (or non-uniform) pricing approach. Once a class revenue requirement is established, the goal for regulators should be one that sets the most appropriate rates based upon various efficiency and equity considerations. Balancing the weight of how costs are recovered between fixed rates, variable rates, block rates, and seasonal rates are all integrated parts of that process.

Q. WHAT IS THE APPROPRIATE ROLE OF COSTS IN SETTING RATES BASED UPON A TWO-PART TARIFF?

A. Costs can be instructive in establishing a baseline upon which prices may be set, but costs need not serve as the sole or exclusive basis for rates in order for them to be set optimally (i.e., fixed charges need not strictly equal fixed costs, variable rates need not strictly equal variable costs). Unfortunately, the "fixed charge-equals-fixed cost" dogma gets repeated so often that it can often drown out meaningful discussions about other equally important considerations in setting rates in imperfect markets. In fact, appropriate rate setting in the context of a two-part tariff typically has more to do with consumer demand than it does with cost.

Q. DID YOU PREPARE AN ANALYSIS OF COSTS COMMONLY ASSOCIATED WITH SYSTEM OR CUSTOMER CHARGES?

A. Yes, and that has been provided in Schedule DED-17. "Customer-related" expense accounts are those typically allocated on the basis of customers and include: removing and setting meters; maintenance of meters; services expense; maintenance of services; meter reading expense; customer records and collections; customer billing and accounting; customer service and information; and sales expense. These costs can also include the depreciation expense associated with the services and meter plant accounts and property taxes as well as the carrying charges (at the Company's requested rate of return) for the customer portion of services investment and 100 percent of the meters investment.

Q. WHAT DO THE RESULTS OF YOUR ANALYSIS SHOW?

A. In most cases, the Company's current customer charges are insufficient to recover commonly-recognized customer costs. The Residential classes' customer-related costs are $15.64 compared to the current customer charge revenue per customer of $9.34. The Small General Service class[71] is estimated to have customer-related costs at $26.71 compared to its current system charge revenue per customer of $19.42.

[71] In the CCOSS, the Small General Service class is combined with Small General Service-Water Heating, Small General Service-Space Heating, and Medium General Service classes.

Q. WHAT ARE YOUR CUSTOMER CHARGE RECOMMENDATIONS?

A. My specific customer charge recommendations are provided on Schedule DED-15. My recommended customer charges move classes currently recovering revenues that are lower than their customer-related costs towards their full costs of service. This increase, however, is capped to a level that is identical to the limitation applied in the first step of my revenue distribution.

D. VOLUMETRIC CHARGES

Q. WOULD YOU PLEASE EXPLAIN THE COMPANY'S VOLUMETRIC DISTRIBUTION RATE PROPOSALS?

A. Yes. For most classes, the Company proposes to recover the remaining portion of a class' revenue requirement through the energy charges. However, for those classes that also have a demand charge, the entire remainder of the class' revenue increase is recovered through the demand charge, with no part flowing through the energy charge.[72]

Q. WHAT ARE YOUR VOLUMETRIC RATE RECOMMENDATIONS?

A. My volumetric rate recommendations differ from those offered by the Company. These differences are a function of my alternative CCOSS, the resulting alternative revenue distribution, my recommended customer charges, and the treatment of demand charges. My customer charge recommendations assess class-specific, customer-related costs to each recommended class-specific customer charge. Costs not recovered through the customer charge are recovered through volumetric charges. For those classes that have a Demand Charge and a Delivery Service Rate, I retain the existing relationship between the demand charge and the delivery rate and

[72] Marlene C. Santacecilia, Direct Testimony, (MCS)-1.

recommend allocating the increase on an equal percentage basis between the two components. My alternative rates based upon my alternative CCOSS and recommended revenue distribution are provided in Schedule DED-15.

E. RATE DESIGN RECOMMENDATIONS

Q. WOULD YOU PLEASE SUMMARIZE YOUR RATE DESIGN RECOMMENDATIONS?

A. Yes. My rate design recommendations can be summarized as follows:

- Revenue responsibilities for developing rates should be allocated using a two-step methodology. The first step limits the rate increase to any under-earning class, and the second step distributes any remaining revenue deficiency across all other classes in proportion to their test year revenue.
- Existing customer charges should be increased for those classes where their current revenues are less than their customer-related costs to a level that moves towards their full cost of service.
- After developing the customer charges, the remaining costs are recovered through volumetric charges. For those classes that have a Demand Charge and a Delivery Service Rate, I recommend allocating the increase on an equal percentage basis between the demand charge and the delivery rate to maintain the existing relationship between the two components.

Q. DOES THIS COMPLETE YOUR TESTIMONY PREFILED ON AUGUST 16, 2013?

A. Yes, it does.