Dr. Luznar's final recommendation was that Pepco's actual capital structure of 51.11% long-term debt and 48.89% common equity be approved, and that ROE be set at 9.36%, with the Company's overall cost of capital being 7.63%,[434] as follows:

Type of Capital	Ratio		Cost Rate		
Long-Term Debt	51.11%	X	5.96%	=	3.05%
Equity	48.89%	X	9.36%	=	4.58%
					7.63%

3. Commission Decision

a. Cost of Equity

As recently as July 20, 2012, we issued a decision addressing Pepco's last application for a rate increase.[435] There we found Pepco's request for a 10.75% ROE "excessive and totally unjustified."[436] We determined that Pepco faced minimal risk because of its status as a monopoly provider of electric distribution service, its lack of ownership of any generating facilities, and its stable service territory. Additionally, we found that the low interest rate environment that existed at the time of the Order provided Pepco with ample opportunity to attract necessary capital at reasonable rates. Finally, we examined Pepco's rate request in light of its history of service reliability problems, and concluded that we would not reward Pepco for poor reliability performance and historic system neglect. We observed: "We cannot and will not allow Pepco . . . to reap growing profits while it provides subpar service to its customers."[437] In considering the relevant economic factors Pepco faced at the time, the company's need for capital, and its service

[434] Luznar Surrebuttal at 11.
[435] *In the Matter of the Application of Potomac Electric Power Company for Authority to Increase Its Rates and Charges for Electric Distribution Service*, Case No. 9286, Order No. 85028.
[436] Order No. 85028 at 107.
[437] *Id.* at 107, 109.

reliability issues, we concluded that in Case No. 9286 we would grant Pepco a return on equity of 9.31%.[438]

The obvious question in this case, therefore, regarding Pepco's request for a 10.25% ROE[439] is, what has changed in less than one year since we last established a just and reasonable ROE, that now might justify a higher return?

Pepco has not demonstrated any significant changes in the economic environment faced by the Company. It is still a monopolistic provider of electric distribution service that operates in a stable service territory. Its customer base is heavily residential, which alleviates the risk of large scale closures or relocations faced by utilities operating in heavily dense commercial or industrial service territories. It does not own generation, which reduces the danger of market price fluctuations and environmental compliance issues faced by generation owners. Moreover, while the Company has taken certain actions to improve its reliability service, it is noteworthy that only four months passed between our determination on July 20, 2012 that Pepco's ROE should be 9.31%, and the Company's current filing for a new rate case on November 30, 2012..

As evidence of changes in current and expected capital market conditions, Pepco witness Hevert pointed to the Federal Reserve's policy of buying longer-dated Treasury securities and selling short-term securities to drive down long-term interest rates.[440] In certain respects, he asserted, the low-interest rate environment is artificial and it could

[438] Order No. 85028 at 109.
[439] Pepco Initial Brief at 5.
[440] Hevert Direct at 40-41. Mr. Hevert also requests an upward adjustment of Pepco's ROE to compensate for the "Company's comparatively small size," which, according to Mr. Hevert, adds additional risk to investors. Hevert Direct at 28. As discussed below, however, Pepco's size did not prevent it from recently obtaining $450 million in new long-term debt. Additionally, Mr. Hevert concedes that "Pepco is not a separately traded entity," but rather, is a subsidiary of its PHI parent. *Id.* at 29. Finally, Pepco's size is not a "new" issue, but rather a factor considered by the Commission in the Company's previous rate case proceeding, wherein the Commission determined that a 9.31 percent ROE was just and reasonable.

change in the future. He concluded that "investor risk aversion and Federal monetary policy were the primary factors underlying the unprecedented decline in Treasury yields."[441] Nevertheless, Pepco is currently facing a low-interest rate environment,[442] regardless of whether the cause is Federal Reserve policy, a continued slow recovery from a historic recession, or both. Given Pepco's predilection for filing rate cases frequently with the Commission, we see no logic in inflating Pepco's ROE today, during a time of historic low interest rates, based on speculation that those rates could increase sometime beyond the Company's likely rate effective period. Moreover, as Mr. Hevert[443] and Mr. King[444] testified, PHI had no difficulty raising a significant quantity of capital in its recent debt issuances. To the contrary, the Company generated $450 million of new long-term debt between April 2012 and March 2013.[445] For that reason, OPC argues that Pepco's current ROE of 9.31% should be viewed as a ceiling on any ROE award.[446] While we may not agree with OPC's strict ceiling, we do agree that Pepco has demonstrated its access to necessary capital on reasonable terms through its recent debt issuances and capital infusions, and conversely has not demonstrated a need for an increase in its ROE.

Finding no significant factors that justify a radical departure from the ROE previously granted to Pepco, we now turn to the specific methodologies utilized by the parties. Witnesses for Pepco, Staff, OPC, and AOBA provided similar analytical methods for evaluating a just and reasonable ROE for the Company. For example, all

[441] Hevert Rebuttal at 5
[442] King Direct at 11-12.
[443] T at 1146 (Hevert).
[444] T at 1632 (King).
[445] Specifically, Pepco issued $200 million of 10-year bonds on April 4, 2012 at a coupon rate of 3.05 percent, and $250 million of 30-year bonds on March 11, 2013 at a coupon rate of 4.15 percent.
[446] OPC Initial Brief at 80.

four parties employed the standard DCF analysis and CAPM methodology. Additionally, the Company and at least one intervening party used the ECAPM analysis and the build-up methodology. Staff alone utilized the Internal Rate of Return model and OPC added the two-step DCF analysis and sustainable growth DCF analysis. We find all of these analytical tools helpful and will not rely on any one to the exclusion of the others.

As testified by the various cost of capital witnesses, each methodology requires some level of judgment and assumptions. For example, the parties differ in their determination of the most appropriate proxy groups, as well as their use of certain specifications and inputs, such as the growth rate assumptions used in the DCF analysis and estimates of the risk-free rate used in the CAPM test. The parties have also used judgment in weighing the results of the different methodologies utilized.

Considering all of the methodologies presented, we will accept Staff's recommended ROE of 9.36% as just and reasonable. In reaching this conclusion, we are guided by the principles of *Bluefield Water Works*[447] and *Hope Natural Gas*,[448] which require a return that is sufficient to attract capital on reasonable terms, maintain the financial integrity of the utility, and provide an opportunity to achieve a level of revenue commensurate with that available in other investments of similar risk. Both OPC and

[447] 262 U.S. 679 at 692. The Court held "A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding, risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties."

[448] 320 U.S. 591 at 603. The Court stated "the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital."

AOBA advocated for a lower ROE (9.1% and 9.3%, respectively), while Pepco's 10.25% proposal is anomalously high in relation to the other recommendations and well above the 9.31% ROE approved by the Commission less than one year ago.[449]

Our approval of a 9.36% ROE includes flotation costs.[450] We accept the calculations of Staff and OPC that demonstrate Pepco's flotation costs to be eight basis points.[451] We decline to accept Mr. Hevert's recommendation that Pepco receive flotation costs amounting to 14 basis points, as his calculation is based on his premise that equity and the costs behind it have "an indefinite life."[452] We have rejected that conclusion in past rate case proceedings, as Mr. Hevert concedes,[453] and we are not convinced to diverge from that precedent.

b. <u>BSA and GRC</u>

We will not reduce Pepco's ROE by a specific amount because of its Bill Stabilization Adjustment Rider ("BSA"). The BSA was designed to account for changes in electricity usage due to variations in weather and state-mandated energy-efficiency and conservation programs, and to remove the disincentive a utility would otherwise have to promote such programs, which, in the absence of the BSA, could reduce the company's sales revenue. In Pepco's last rate case, we upheld a 50 basis point reduction to the

---

[449] We observe that the 9.36 percent ROE we find just and reasonable today is within the range of ROE calculations provided by Mr. Hevert in his standard DCF, CAPM, and ECAPM analyses. *See* Staff Initial Brief at 20. His use of weighting factors and overreliance on generation-owning utilities in his Electric Utility Proxy Group, which we do not find reasonable, contributed to his excessive 10.25 percent ROE recommendation.
[450] Flotation costs are the expenses associated with the sale of new issues of common stock. These costs include out-of-pocket expenditures for preparation, filing, underwriting, and other costs of issuance. Hevert Direct at 30.
[451] King Surrebuttal at 6, Luznar Direct at 17, 19.
[452] Hevert Direct at 31. In contrast, Staff witness Dr. Luznar estimated the flotation cost by amortizing PHI's actual flotation costs over ten years, then dividing that amount by PHI's market capitalization. Luznar Direct at 17.
[453] Hevert Rebuttal at 27, Case No. 9286, Order No. 85028 at 109.

Company's ROE as a result of the previous approval of Pepco's BSA.[454] The BSA stabilizes Pepco's earnings by decoupling its distribution revenues from its volumetric sales, thereby helping ensure recovery of the Company's revenue requirement and reducing regulatory lag. Without the BSA, "Pepco would see more dramatic swings in its earnings than currently."[455] Because of those benefits, OPC and AOBA argue that Pepco's current ROE award should be reduced by a similar amount.[456]

As noted by Pepco and Staff, however, we have recently issued two orders in Case No. 9257 that have somewhat altered the Company's risk as it relates to decoupling. In Order No. 84653, we determined that Maryland utilities with BSAs, including Pepco, will be prohibited from collecting lost utility revenue through their decoupling mechanisms if the utilities are unable to restore service to their customers within 24 hours of the onset of a Major Storm.[457] We stated that the BSA suspension will exist for the time period beginning 24 hours after the onset of a Major Storm and continuing until all Major Storm-related interruptions are restored.[458] In the more recent Order No. 85177,[459] we determined that utilities will be prevented from collecting decoupling revenue even during the first 24 hours of a Major Outage Event.[460] As a result of these orders, the risk-

[454] The Commission approved a BSA decoupling mechanism for Pepco in Case No. 9092 on July 19, 2007 in Order No. 81517 (at 81-82).
[455] Order No. 85028 at 109.
[456] OPC Initial Brief at 76, Oliver Direct at 49.
[457] *In The Matter of the Investigation into the Just and Reasonableness of Rates as Calculated Under the Bill Stabilization Adjustment Rider of Potomac Electric Power Company*, Case No. 9257, Order No. 84653, (Jan. 2012).
[458] The Commission made the decision to remove collection of BSA revenue from storm-related outages in order to properly align the utilities' incentives and to prevent an inequitable burden on customers, who often face exceptional hardship as a result of electric outages caused by storm events.
[459] *In The Matter of the Investigation into the Just and Reasonableness of Rates as Calculated Under the Bill Stabilization Adjustment Rider of Potomac Electric Power Company*, Case No. 9257, Order No. 85177, (Oct. 2012).
[460] Subsequent to the issuance of Order No. 84653, through the RM43 rulemaking proceeding, the Commission replaced the term Major Storm with Major Outage Event. COMAR 20.50.01.03.B(27) defines Major Outage Event as an event in which more than 10 percent or 100,000, whichever is less, of the

reducing benefits of the BSA to Pepco are somewhat diminished, and the rationale for an explicit reduction in the ROE less certain.

In Order No. 85374, issued on February 22, 2013, we most recently addressed the BSA as it relates to BGE's rate proceeding.[461] There, as a result of the issuance of Order Nos. 84653 and 85177, and the greater prevalence of BSAs in electric utility proxy groups, we found that "a strict basis point reduction of 50 points may no longer be warranted."[462] We find so here as well. We will not reduce Pepco's ROE by an express amount as a result of its BSA, though we will, as in BGE's proceeding, consider the BSA as one of many relevant variables that informs our determination of a just and reasonable return.[463]

Mr. King testified on behalf of OPC that Pepco's ROE should be further reduced if the Commission grants the Company's request for a GRC. Mr. King asserted that the surcharge would lower the Company's revenue risk. Accordingly, Mr. King contended that Pepco's ROE should be lowered by between 25 and 91 basis points if the GRC is approved.[464] Given the limited scope of the GRC approved in this Order, we will not address this recommendation.

---

electric utility's Maryland Customers experience a sustained interruption of electric service; and restoration of electric service to any of these customers takes more than 24 hours; or the federal, State, or local government declares an official state of emergency in the utility's service territory and the emergency involves interruption of electric service.

[461] *In the Matter of the Application of Baltimore Gas and Electric Company for Adjustment in its Electric and Gas Base Rates,* Case No. 9299, Order No. 85374 (Feb. 2013).

[462] Order No. 85374 at 66.

[463] In the BGE rate proceeding, the Commission held that BGE's BSA "remains a 'very good' decoupling mechanism, better than almost all others in any of the experts' proxy groups, which serves to limit the risk, and therefore the appropriate ROE for BGE." *Id.* (Internal citations omitted).

[464] King Direct at 38-39, King Surrebuttal at 7-8.

c. Capital Structure

Pepco's initial application proposed a capital structure of 49.45% common equity and 50.55% long-term debt.[465] However, the Company revised its application to reflect a $250 million debt issuance and $175 million contribution to equity.[466] OPC and Staff accept the Company's proposed capital structure.[467]

AOBA argues, however, that Pepco's proposed capital structure does not represent the Commission-required actual capital structure because it includes debt and equity infusions after the close of the test year and because it omits the substantial short-term debt utilized by the Company during the test year.[468] It is our long-standing policy to base the utility's return on its actual capital structure absent evidence that the actual capital structure would impose an undue burden on ratepayers.[469] We find no evidence in the present case that Pepco's proposed capital structure would be unduly burdensome to the Company's ratepayers. However, it is also our general policy to base a utility's return on its capital structure as it existed at the end of the test year. Here, Pepco has asked that we accept modifications to the Company's capital structure as it existed at the end of the test year (December 31, 2013), including the Company's $250 million long-term debt issuance and $175 million equity contribution from PHI in March 2013. We find the modifications to the Company's end of the test year capital structure to be known and measurable and therefore appropriately included in the Company's proposed capital structure. We also find that the short-term debt utilized by the Company was used

[465] Hevert Direct at 2, 47, 49.
[466] Boyle Supplemental Rebuttal at 1, 2.
[467] OPC Initial Brief at 67, Luznar Surrebuttal at 3, 11.
[468] AOBA Initial Brief at 21. Accordingly, AOBA proposes a capital structure that is 48.22% long-term debt, 5.84% short-term debt, and 45.94% equity.
[469] *Re Potomac Elec. Power Co.*, 98 MD PSC 228, 269 (2007).

primarily to fund CWIP and other long-term construction projects, and that it was therefore properly excluded by Pepco from its proposed capital structure.[470] Accordingly, we accept the capital structure proposed by Pepco of 51.11% long-term debt and 48.49% common equity.

Finally, AOBA argues that Pepco's proposed 6.21% average cost of long-term debt is unwarranted because the Company incurred inappropriately high debt issuance costs and because it has not effectively managed its long-term debt.[471] We will not reduce Pepco's long-term debt interest rate as AOBA requested. We do not find that the Company incurred imprudently high debt issuance costs and we will not second guess the Company's decision in hindsight to enter into a long-term bond issuance in December 2008 at rates that in retrospect may appear high, without further evidence of imprudence.

Accordingly, we approve the following weighted average cost of capital for Pepco:

Type of Capital	Percent of Total Capital	Embedded Cost Rate	Weighted Cost Rate
Long-Term Debt	51.11%	5.96%	3.05%
Common Equity	48.89%	9.36%	4.58%
	100.00%		7.63%

C. Cost of Service

1. Parties' Positions

a. Pepco

Witness Christopher A. Nagle sponsored the Company's Maryland Jurisdictional Cost of Service Study ("COSS") and Adjusted Maryland Class of Business Cost of

[470] Luznar Surrebuttal at 3-4.
[471] AOBA Initial Brief at 38-40. OPC and Staff accepted the long-term debt cost calculation of 5.96 percent proposed by Pepco witness Mr. Boyle. OPC Initial Brief at 67, Staff Initial Brief at 21.

Service Study ("CCOSS"), based on the 12-month period ending December 31, 2012.[472] Company witness Joseph J. Janocha incorporated the results from the CCOSS in developing the Company's recommended rate design.[473]

According to Mr. Nagle, the Company has complied with the cost of service-related directives issued by the Commission in its last rate case in Order No. 85028.[474] The COSS presented as Schedule (CAN)-1 incorporates the Average and Excess Non-coincident Peak Demand (AED-NCP) method to allocate sub-transmission plant, and the CCOSS presented as Schedule (CAN)-2 incorporates the Average and Excess Non-coincident Area Peak Demand (AED-NCAP) method of allocating sub-transmission.[475] The Company provided a comparison between those methods and the method the Company had traditionally used, the Average and Excess Four-Month Average Coincident Peak Demand (AED-4CP) method, in Schedule (CAN)-4.[476]

The COSS was developed to assign and allocate each element of rate base, revenues, and expenses between the Company's customers in its Maryland and District of Columbia service territories.[477] The allocations in the Company's COSS are driven primarily by direct jurisdictional assignments and allocations of plant, depreciation expense, and operations and maintenance (O&M) expense, as well as detailed analyses conducted for select elements of the COSS.[478]

---

[472] Nagle Direct at 2.
[473] Janocha Direct at 4.
[474] Nagle Direct at 2.
[475] *Id.* at 2.
[476] Currier Direct at 33.
[477] Nagle Direct at 6.
[478] *Id.* at 6-7.

The Company's electric plant in service (EPIS) is maintained in the Company's asset accounting system based upon the FERC Uniform System of Accounts.[479] Sub-transmission and distribution plant are distinguished, along with general and intangible plant assets.[480]

The CCOSS was developed to assign and allocate each element of rate base, revenues, and expenses to the Company's customer classes within Maryland.[481] The majority of the Company's distribution facilities are primary and secondary voltage systems (distribution substations, overhead and underground lines, transformers). These serve customers in a local area and are therefore directly assigned to the appropriate jurisdiction.[482] Sub-transmission related plant facilities are allocated using an AED-NCAP method as directed by the Commission in Order No. 85028.[483] Distribution and general depreciation expenses are assigned to jurisdictions based on Company records.[484] Distribution plant at the primary and secondary voltage levels is allocated to customer class using NCAP and/or sum of customer maximum (defined by Staff as NCD) demands.[485] The various FERC accounts designating customer-related distribution plant are allocated and assigned in the same manner as past rate cases including Case No. 9286.[486] The Company allocated general and intangible plant using a sub-transmission and distribution plant allocator as was accepted in Case No. 9286. Depreciation and O&M expenses are generally allocated in-line with the corresponding EPIS functions or FERC accounts. Distribution O&M expenses are assigned to jurisdictions based on the

---

479 Nagle Direct at 7.
480 *Id.* at 7.
481 *Id.* at 9.
482 *Id.* at 7.
483 *Id.* at 10.
484 *Id.* at 8.
485 *Id.* at 10.
486 *Id.* at 10-11.

2011 detailed analyses of O&M FERC accounts or allocated using relevant plant ratios.[487] Administrative and general (A&G) expenses are allocated based on the O&M expense less A&G, storm, and tree trimming allocator.[488] The allocation of customer accounts and sales expense is based on the Company's 2011 analysis and then allocated to jurisdictions based on the number of customers in the test period.[489] Schedule (CAN)-5 compares the results of the CCOSS as presented in Schedule (CAN)-2 and the results of the CCOSS with the PSC Assessment allocated based upon gross Maryland retail sales, as ordered by the Commission in Order No. 85028.[490]

The Company's proposed customer-class rates of return and relative rates of return for the test period are[491]:

Customer Class	Rate of Return	Relative Return
Residential	3.32%	0.61
RTM	3.26%	0.59
GS-LV	5.68%	1.04
MGT-LV	8.36%	1.53
MGT-HV	17.90%	3.27
GT-LV	9.58%	1.75
GT-HV-69kV	23.28%	4.25
GT-HV-Other	6.92%	1.26
Metro	8.95%	1.64
Street Lighting-E	9.42%	1.72
Street Lighting-S	5.12%	0.94
TN	35.57%	6.50

[487] Nagle Direct at 8.
[488] *Id.* at 8.
[489] *Id.* at 11.
[490] *Id.* at 4.
[491] Campbell Rebuttal, Exhibit GMC-R-1.

b. OPC

OPC agreed that the Company has complied with the requirement to include a comparison of the AED-4CP and AED-NCP allocation methods in this case, the comparison presented in Schedule (CAN)-4.

OPC Witness Dismukes disagreed with three allocation factors and assumptions used by the Company in its CCOSS. He disagreed with: (1) the use of AED-NCP to allocate sub-transmission rate base assets and related expenses; (2) the use of the sum of customer maximum (defined by Staff as NCD) demand to allocate secondary voltage distribution plant accounts and related operations and maintenance expenses; and (3) the use of total sub-transmission and distribution plant as an allocation factor of Commission assessments. Dr. Dismukes admitted that there is not a significant difference between the AED-4CP and AED-NCP allocation methodologies,[492] however, he opined that absent substantial support for a change in methodology, the historical use of the AED-4CP method should be retained.[493] Instead of using 100 percent of NCP to allocate secondary voltage distribution plant accounts and related operations and maintenance expenses, Dr. Dismukes recommended that the Commission use 50 percent NCP and 50 percent NCAP in order to give equal weight to both measures of demand placed on the secondary distribution system.[494] Dr. Dismukes disagreed with the Company's allocation of Commission assessments on the basis of total sub-transmission and distribution plant. He recommended allocating these expenses based on gross Maryland retail sales revenue, which in his opinion more accurately reflects the fact that, pursuant to §2-110 of the Public Utilities Article, Commission regulatory assessments are calculated based on a

[492] Dismukes Direct at 77.
[493] *Id.* at 78.
[494] *Id.* at 80.

ratio of gross operating revenues between jurisdictional utilities.[495] Dr. Dismukes' alternative CCOSS is contained in Schedule DED-17 to his direct testimony.

Dr. Dismukes agreed with the Company's use of allocators derived from four cost allocation studies relied on by the Company, however, he noted that much of the data within the studies is four years out of date.[496] The Company relied on the studies to derive relevant allocation factors associated with certain Distribution Plant Accounts and Customer Accounts and Sales Expense Accounts, which include: (1) an embedded cost of meters study, (2) an installation on customer premises cost study, (3) an outdoor lighting cost study, and (4) a customer accounts and sales expense cost study.[497] In response to a data request from Commission Staff, the Company stated that it anticipates performing a new meter cost allocation study as soon as its AMI system rollout is complete.[498] Dr. Dismukes opined that the Commission should direct the Company to update its meter cost study as well as its other cost allocation studies before its next base-rate case.[499]

c. AOBA

AOBA witness Oliver conducted a comparison of the relative or unitized rates of return (UROR) in this rate case with those in Case Nos. 9217 and 9286. Mr. Oliver stated that the disparity in class returns has not improved since Case No. 9217, and that the rates of return for the GT-LV, Metro and GT-HV classes are now farther from the system average than they were in Case No. 9217.[500]

---

[495] Dismukes Direct at 80.
[496] *Id.* at 82.
[497] *Id.* at 80-81.
[498] *Id.* at 81.
[499] *Id.* at 82-83.
[500] Oliver Direct at 68.

AOBA also asserted that the Company's allocation of income taxes among rate classes is inappropriate because the non-residential classes are assigned more than 100% of the total jurisdictional Federal Income Tax liability. Mr. Oliver claimed that Rate Schedules GT and MGT are assigned over 1.4 times the Company's Maryland jurisdictional Federal Income Tax expense.[501] Mr. Oliver asserted the Company should allocate income tax responsibilities among rate classes based on the percentage of the Company's rate base for which each class is responsible.[502]

Mr. Oliver claimed that the Company has employed an overly broad-brush approach to the allocation of costs, and thus has failed to properly assess class responsibilities for a number of large dollar amounts.[503]

d. Staff

Staff agreed that the Company has complied with the Commission's directive in Order No. 85028 in that its COSS uses the AED-NCP method to allocate sub-transmission plant and compares it to the AED-4CP method Pepco has traditionally used.[504]

Staff noted that the Company's COSS indicates a total system rate base of more than $2.5 billion, of which 46% is allocated to Maryland.[505] The Company calculated the ROR for the Maryland jurisdiction to be 5.73% as of December 31, 2012.[506] The rate of return for Maryland increased by more than two percentage points largely because expenses decreased by more than $30 million, causing the net income provided by the

[501] Oliver Direct at 70.
[502] *Id.* at 73.
[503] *Id.* at 76-77.
[504] Currier Direct at 33.
[505] *Id.* at 18.
[506] *Id.* at 18.

jurisdiction to increase.[507] Of the $30 million decrease, $25 million was in expenses under FERC account 593, Maintain Overhead Lines, because of credits that were recorded to defer the Maryland portion of major storm costs in 2012.[508]

Staff Witness Currier noted that one of the key outputs from the CCOSS is the UROR which measures the return of a customer class with respect to the system average.[509] URORs have moved closer to 1 since the previous rate case, Case No. 9286.[510] The residential class in particular has moved dramatically closer to the system average since July 2012, while Overhead Lines Maintenance Expense decreased.[511] Street lighting is nearly at the system average when just last year it was earning three times as much, largely due to increased expenses allocated to the street lighting class.[512]

Staff supported use of the Company's CCOSS to aid in rate design. Mr. Currier found the CCOSS to be reasonable, and, with a few exceptions, consistent with the CCOSS filed in Case No. 9286.[513] Staff did recommend that the Commission direct the company to provide a rate class ROR and UROR comparison conforming to Staff's recommendation regarding the allocation of AFUDC in this proceeding (AFUDC would be allowed on the basis of its respective plant and not a composite allocator).[514] The rate base allocation percentages in both 2012 and 2011 are approximately the same among the Company's customer classes.[515] The residential classes are still allocated more than half of the Company's total rate base and the MGT classes are allocated a little more than a

---

507 Currier Direct at 18.
508 *Id.* at 19.
509 *Id.* at 19.
510 *Id.* at 20.
511 *Id.* at 20-21.
512 *Id.* at 21-22.
513 *Id.* at 22.
514 *Id.* at 22.
515 *Id.* at 23.

quarter of rate base.[516] Because the Company's cost of service is largely based on demand allocators, approximately 82% of the Company's rate base is demand related and 18% is customer related.[517]

2. Parties' Responses

a. Pepco

Company Witness Nagle maintained that although Order No. 85028 directed the Company to present a comparison of the AED-4CP and AED-NCP methods, the Order further directed the Company to use the AED-NCP method to allocate sub-transmission plant in this next rate case.[518]

Despite the fact that the Company categorized and allocated the AFUDC in prior cases including Case 9286, the Company now claims that the separation of the sub-transmission and distribution portions of plant AFUDC requires time-consuming analysis that is unnecessary as AFUDC can be reasonably allocated as a whole.[519] The Company provided a comparison of CCOSS results from which it concluded that the difference is negligible.[520]

The Company disagreed with Dr. Dismukes' recommendation to allocate the PSC Assessment on gross Maryland retail sales. Mr. Nagle stated that an allocation based on revenues will perpetuate existing class rate of return inequalities.[521]

The Company did not believe that AOBA Witness Oliver's recommended allocation of income taxes based on total rate base is a reasonable approach in cost of

---

[516] Currier Direct at 23.
[517] *Id.* at 23.
[518] Nagle Rebuttal at 3.
[519] *Id.* at 2.
[520] *Id.* at 3.
[521] *Id.* at 4.

service studies. Mr. Nagle pointed out that Mr. Oliver's proposal would produce a different effective tax rate for every customer class, which in his opinion ignores cost causation.[522]

b. AOBA' s Rebuttal to OPC

AOBA Witness Oliver did not believe that Dr. Dismukes provided substantial justification for his proposed change in the allocation of costs associated with secondary distribution lines to an allocation based on 50 percent NCP and 50 percent NCAP.[523] Mr. Oliver agreed that the allocation of PSC Assessments are more appropriately allocated on the basis of Maryland Gross Revenue by class, but did not agree that the measures of revenue by class that Witness Dismukes uses properly portrays the Company's total Maryland Gross Revenue.[524] He instead believed Maryland Gross Revenue should include SOS revenue and should exclude pass-through taxes.[525]

c. Staff's Rebuttal to AOBA and OPC

Mr. Currier found Mr. Oliver's recommendation that federal and state income taxes be allocated to the Company's customer classes on the basis of rate base to be reasonable and believed that it should be considered by the Commission going forward.[526] Mr. Currier suggested that the Commission direct the Company to present a CCOSS using this proposal and provide a comparison to the method the Company has traditionally used.[527] If all classes provide the system rate of return, then allocating the income tax on the basis of taxable income would be appropriate, however, rates rarely

[522] Nagle Rebuttal at 4-5.
[523] Oliver Rebuttal at 9.
[524] *Id.* at 10.
[525] *Id.* at 10.
[526] Currier Rebuttal at 4.
[527] *Id.* at 1.

provide the same rate of return for each customer class; inter-class subsidization almost always exists.[528] Because the residential customer class is not providing the system's average rate of return, its taxable income is less than it otherwise would be and consequently its tax liability under the Company's current allocation methodology is also (noticeably) lower.[529] If AOBA's income tax allocation method is used, all classes' UROR moves farther from 1, and the inter-class subsidization from the non-residential classes to the residential classes is illustrated.[530] Mr. Currier claimed this shift indicates that the residential classes are earning a lower rate of return, and thus a larger rate increase is necessary to bring the residential classes to the system average.[531]

With regard to Dr. Dismukes' disagreement with the Company's sub-transmission allocation method, Staff recommended that the AED-NCP method be accepted because it complies with the Commission's Order and is more consistent with cost causation.[532] With regard to Dr. Dismukes' proposed change in the allocation of costs associated with secondary distribution lines to an allocation based on 50% NCP and 50 % NCAP, Staff responded that the Company's allocation method using Sum of Customer Max (NCP) should be accepted because it has been consistently been used and accepted; this allocation method should be retained absent substantial evidence that it is unreasonable.[533] With regard to the PSC Assessment, Staff recommended retention of the Company's allocation method because it follows Commission precedent and also helps prevent further distortion in the class relationships between costs and revenues.[534]

[528] Currier Rebuttal at 4.
[529] *Id.* at 4.
[530] *Id.* at 5.
[531] *Id.* at 5.
[532] *Id.* at 7-8.
[533] *Id.* at 8.
[534] *Id.* at 9.

d. AOBA's Surrebuttal to the Company

With regard to Company Mr. Nagle's argument that AOBA's recommended allocation of income taxes based on total rate base would produce a different effective tax rate for every customer class, Mr. Oliver responded by stating that the Federal Tax Code often applies different tax rates to individuals and other taxable entities having different levels of taxable income.[535] Mr. Oliver maintained that the Company's income tax responsibility is appropriately allocated among rate classes based on the returns required to support the rate based investment that the Company incurs to support its provision of service to each rate class.[536] Mr. Oliver noted that although Mr. Nagle's allocation methods for A&G expenses and G&I costs are accepted by NARUC in its cost allocation manual, it is not a proscriptive document; the cost of service analyst must also apply approximate experience, sensitivity, and knowledge of cost incurrence patterns to assess the appropriateness of alternative cost allocation methods.[537] Mr. Oliver noted that large increases in Outside Services render the Company's allocations of G& A costs increasingly important.[538]

e. Staff's Surrebuttal to the Company

Mr. Currier noted that while the Company claimed that allocating AFUCD to each rate class on the basis of distribution and sub-transmission plant ratio is time-consuming, the Company did not provide an estimate of the time and cost required to allocate the AFUCD in greater detail.[539] Staff argued the Company has not proven why it

[535] Oliver Surrebuttal at 31-32.
[536] *Id.* at 32.
[537] *Id.* at 33.
[538] *Id.* at 33.
[539] Currier Surrebuttal at 2.

should be allowed to change its allocation method from the one used in Case No. 9286 to one that is more general in nature.[540]

3. Commission Decision

AED-NCP vs. AED-4CP

The Company and Staff are correct. Our Order No. 85028 directed the Company to present a comparison of the AED-4CP and AED-NCP methods, but directed the Company to use the AED-NCP method to allocate sub-transmission plant in its next rate case. Based on a review of this comparison and the record in this case, including the testimony of Company Witness Nagle, the Company need not provide a comparison of the two methods in future cases.

AFUDC

We agree with Staff that the Company has not proven why it should be allowed to change its method of allocating AFUCD from the one used in Case No. 9286 to one that is more general in nature. When questioned by Staff as to how much additional time would be required to allocate AFUCD to each rate class on the basis of distribution and sub-transmission plant ratio, Company Witness Nagle was unable to provide information as to the time or cost required. He testified that to disaggregate the plant AFUDC into a sub-transmission group and a distribution group required analyses that were not performed within his department.[541] A number of analyses must be performed at year end and over the course of the year in order to maintain the balance of the disaggregated AFUDC.[542] Although the Company apparently performed such analyses for past rate cases, the Company did not perform those analyses for this case and the information is

[540] Currier Surrebuttal at 3.
[541] T at 821-822.
[542] T at 822.

not readily available. From the Company-provided comparison of CCOSS results, it appears in this case that the difference resulting from using a composite allocator is negligible.[543] Thus, we will accept the Company's use of a composite allocator for AFUDC for purposes of rate design in this case. However, because we find insufficient evidence to support the Company's unilateral change to a composite allocator, we direct the Company to, in future cases, allocate AFUCD to each rate class on the basis of distribution and sub-transmission plant ratio as Staff recommends.

Commission Assessment

In Order No. 85028 we directed the Company to present a class rate of return comparison using OPC's proposal to allocate the PSC Assessment based upon gross retail sales.[544] This was provided in Schedule (CAN)-5. OPC advocates again, as it did in Case No. 9286, for the allocation of the PSC Assessment to be based on gross retail sales. The Company and Staff remain concerned about further distortion in the class relationships between costs and revenues. Company Witness Nagle offered that if the Commission wants to move to a revenue-based allocator for the PSC Assessment, in order to eliminate the issue of perpetuating existing class rate of return inequalities, a claimed revenue allocator could be used.[545] We find the Company's allocation method reasonable, formulating part of a CCOSS that, with a few minor adjustments, will fairly and reasonably distribute costs among the Company's customer classes. However, for the point of comparison, we direct the Company, in its next rate case, to present a comparison of the method traditionally used with an allocation based on a claimed

[543] Nagle Rebuttal at 3.
[544] Order No. 85028, p. 118.
[545] T at 825-826.

revenue allocator as the Company has offered could be used and would eliminate the issue of perpetuating class ROR inequalities.

Income Taxes

AOBA again advocates for allocation of federal and state income taxes to the Company's customer classes on the basis of rate base, however, we believe the Company's current allocation method is reasonable.

Conclusion

In summary, we will employ appropriate judgment and discretion in using the CCOSS thus developed to set the final customer class rates based on the record in this case.

D. Rate Design

1. Parties' Positions

a. Pepco

Witness Joseph F. Janocha sponsored the Company's proposed rate design. The Company's approach used to allocate its proposed revenue requirement among the Company's rate classes begins by summarizing the rate class specific distribution revenue, net operating income, net rate base, rate of return, and UROR results from the CCOSS.[546] The next step involves the allocation of the overall revenue increase on a rate class specific basis.[547]

As directed by Order No. 85028 in Case No. 9286, the Company allocated the revenue increase using a two-step process. First, a portion of the increase was allocated

[546] Janocha Direct at 4.
[547] *Id.* at 4.

to the rate classes with URORs most significantly below 1.0.[548] In the second step, the remainder of the increase was allocated to all rate classes in proportion to their current level of annualized distribution revenue.[549] For Rate Schedules R and RTM, which have existing URORs lower than 1.0, the Company proposed to allocate 25% of the total revenue increase. Rate Schedules MGT-3A, GT-3B, and TN have URORs significantly above 1.0, and therefore, the Company proposed no increase for these rate schedules.[550] The remaining 75% of the increase was allocated to all rate classes (except MGT-3A, GT-3B, and TN) based on their level of current annualized distribution revenue.[551]

For Rate Schedules R, RTM, and GS-LV, the company proposed to increase the customer and volumetric rate components by an equal percentage basis. Rate Schedules MGT-LV, GT-LV, and GT-3A have customer, demand and energy rate components, and the Company proposed that the increase be apportioned to gradually shift the recovery of distribution costs from the volumetric rate component to the customer and demand charge components. The customer charge increased by the same percentage increase as the proposed overall percentage increase for the respective rate class; the demand charges were increased by 1.25 times the overall class percentage increase; and the volumetric component recovered the balance of the proposed distribution revenue level for each class.[552] Under the Company's proposed rate design, a typical residential Standard Offer Service (SOS) customer using 1,000 kWh per month would see a total monthly bill increase of $7.13 or 4.98%.[553]

---

[548] Janocha Direct at 4-5.
[549] *Id.* at 5.
[550] *Id.* at 6.
[551] *Id.* at 7.
[552] *Id.* at 8.
[553] *Id.* at 10.

An adjustment to the revenue-per-customer levels to be used in future BSA calculations is required based on the proposed changes in rates.[554]

Lastly, the Company proposed to design Grid Resiliency Charge rates for each Tariff Rate Schedule based on the class's distribution rate design. For Rate Schedule R, RTM, GS-LV, T (Temporary), EV (Electric Vehicle), SL, and TN, the Grid Resiliency Charge would be designed as a volumetric charge; for Rate Schedules MGT-LV, MGT-3A, GT-LV, GT-3A, and GT-3B, the charge would be designed as a demand charge applicable to the maximum monthly demand; for Rate Schedule OL the charge would be designed as a per-lamp charge.[555]

b. OPC

Dr. Dismukes stated that the rate design goals enumerated by the Company are consistent with Commission precedent.[556] Dr. Dismukes noted that while the Commission ordered the Company to distribute its revenue increase using the two-step approach set forth in Case No. 9286, the Commission did not direct the use of any specific percentage split between under-earning and over-earning classes, nor did it mandate any rate increase exclusion for classes estimated to be significantly over-earning.[557] Dr. Dismukes also noted that in the recent Baltimore Gas & Electric Company (BGE) rate case, the Commission rejected BGE's proposal to allocate 50% of the rate increase to the under-earning classes, as well as Staff's proposal to allocate 25% to the same classes.[558] Instead, the Commission found a more gradual rate increase was appropriate, and assigned 15 percent of the overall authorized increase to the under-

[554] Janocha Direct at 10-11.
[555] *Id.* at 13-14.
[556] Dismukes Direct at 84.
[557] *Id.* at 87.
[558] *Id.* at 88.

earning classes. The remaining part of the authorized increase was assigned to all classes except the highest over-earning classes.[559]

Dr. Dismukes recommended a revenue distribution that constrains any under-earning class from receiving a rate increase no greater than 1.05 times the system average increase, and distributes any remaining revenue deficiency across other classes in proportion to their test year revenue, including the significantly over-earning classes, which differs from the methodology used in the last Pepco rate case.[560] Under OPC's approach, the residential classes would receive 57 percent of the total rate increase instead of the Company's proposed 68 percent.[561]

c. <u>AOBA</u>

Mr. Oliver had two major problems with the methodology the Company used to determine the distribution of its proposed revenue increase among rate classes.[562] *First,* Mr. Oliver did not support the Company's proposal to apply the same percentage increases to a large number of rate classes without consideration for differences in those classes' current rates of return.[563] Mr. Oliver believed that classes with roughly system average rates of return should receive increases that more closely approximate the system average rate increase, and classes with noticeably above average rates of return should receive less than system average increases.[564] *Second,* Mr. Oliver believed that the Company's inclusion of BSA revenue adjustments inappropriately distorts its proposed distribution of the revenue increase because it improperly and unreasonably ratchets class

[559] Dismukes Direct at 88.
[560] *Id.* at 89.
[561] *Id.* at 89.
[562] Oliver Direct at 81.
[563] *Id.* at 81.
[564] *Id.* at 81.

revenue requirements to levels established in prior cases without consideration of changes in class usage characteristics.[565] Mr. Oliver recommended altering the Company's proposed revenue increase distribution to provide greater differentiation of rate increases among non-residential classes of service.

Mr. Oliver had concerns about the Company's rate design presentation. He stated that the rate increases reflected in the Company's bill comparisons [Schedules (JFJ)-3, (JFJ)-8, and (JFJ-S)-3] fail to reasonably portray the rate increases that large numbers of customers will experience if they either (1) are not subject to the Montgomery County Fuel and Energy Tax or (2) do not use Standard Offer Service.[566]

Mr. Oliver pointed out that the Company is still proposing increases to the on-peak demand charges for summer use by medium and large commercial customers (MGT and GT), which are based on embedded seasonal differentials that existed at the time rates were unbundled in July 2000.[567]

Mr. Oliver also argued in addition that the Company's allocation of the incremental Grid Resiliency Charges has no basis in cost causation.[568]

d. Staff

Staff acknowledged that the Company's rate design follows a gradual approach in increasing rates such that no rate would increase by an unreasonable level.[569] Staff Witness Campbell stated that, independent of the magnitude of the revenue to be increased, the Company's rate design process is not unreasonable; the Company adhered

[565] Oliver Direct at 82-83.
[566] *Id.* at 85-86.
[567] *Id.* at 87-89.
[568] *Id.* at 93.
[569] Campbell Direct at 10.

to the directives set forth in Commission Order No. 85028 in Case No. 9286 and used a two-step inter-class rate design method.[570]

Although reasonable given the magnitude of the revenue increase proposed by the Company, Staff proposed a 20% allocation to the over-earning rate classes instead of the Company's proposed 25% allocation, based on the Staff's calculation of a reduced revenue increase.[571] Staff accepted the Company's proposal to raise both the customer and volumetric charges of the R, RTM, and GS-LV rate classes equally.[572] Staff noted that the Company's proposal to raise the demand charge component above the overall rate class increase while maintaining the customer charge increase equivalent to the overall rate class increase is efficient.[573]

2. Parties' Responses

a. Pepco

The Company did not agree with OPC's proposed revenue allocation approach. Company Witness Janocha explained that by employing a constraint that no class receives a percentage increase of more than 1.05 times the overall percentage increase, the allocation of revenue is essentially even across all rate classes, thereby not effectuating the primary purpose of the two-step approach of directing a larger portion of the revenue allocation to classes with rates of return lower than the overall rate of return.[574] As Mr. Janocha explained, under OPC's approach, revenue increases would be directed to three commercial classes (MTF-3A, GT-3B and TN) that have rates of return

[570] Campbell Direct at 10-11.
[571] *Id.* at 12.
[572] *Id.* at 12.
[573] *Id.* at 13.
[574] Janocha Rebuttal at 2.

well above the overall rate of return, which does not reduce the substantial disparity in earnings for these classes.[575]

The Company also did not agree with AOBA's proposed allocation method because it does not use the two-step revenue allocation process and does not take into consideration the annualized authorized revenue which the Company believes is appropriate to incorporate into the rate design calculation.[576]

The Company believed that its bill impact presentation, the same presentation of bills impacts as was used in Case Nos. 9092, 9217, and 9286, accurately portrays the dollar impact of the distribution increase over a range of usage levels.[577]

The Company agreed with the phased elimination of the Summer On-Peak Demand Charge proposed by Mr. Oliver. Mr. Janocha stated that if the Commission prefers the approach of reducing the demand charge by 50% instead of 25%, the Company is willing to support this alternative proposal, as applied to Rate Schedules AGT-LV, MGT-3A, GT-LV, GT-3A and GT-3B.[578]

b. AOBA' s Rebuttal to OPC

AOBA Witness Oliver found OPC Witness Dismukes' proposed distribution of the Company's requested revenue increase to be inequitable because it would apply equal percentage rate increases to classes that have substantially different ROR.[579] Mr. Oliver urged the Commission to reject Dr. Dismukes' rate design recommendations because they perpetuate the Company's use of non-cost-based seasonal rate differentials.[580]

---

[575] Janocha Rebuttal at 2.
[576] *Id.* at 2-3.
[577] *Id.* at 4-5.
[578] *Id.* at 6-7.
[579] Oliver Rebuttal at 12-13.
[580] *Id.* at 13.

c. Staff's Rebuttal to OPC and AOBA

Staff Witness Campbell pointed out that Dr. Dismukes' rate structure based on a maximum increase set at 1.05 times the system average increase, does not abide by the goal of not giving any individual rate class a UROR increase if they are above 1.0 or a decrease if they are under 1.0.[581] Mr. Campbell applied the principle of cost causation and proposed raising the customer charges of the residential and general service low-voltage customers by a percentage equal to the total rate class increase, while Dr. Dismukes recommended keeping the customer charges for these rate classes at their current rate.[582] This difference in proposed rate design reflects the competing principles in rate design.[583] Mr. Campbell noted that while Dr. Dismukes' uses the two-step rate design process, Dr. Dismukes allocates on the basis of distribution revenues whereas Mr. Campbell recommends allocating on the basis of class rate base percentage.[584]

Mr. Campbell disagreed with AOBA Mr. Oliver's recommendation that revenues associated with the BSA should not be considered when determining rate class bill changes; Mr. Campbell argued that BSA-related revenues are necessarily included in order to have an "apples-to-apples" comparison.[585]

d. AOBA's Surrebuttal to the Company and Staff

AOBA Mr. Oliver continued to maintain that his proposed revenue increase distribution is more appropriate than the Company's.[586] He found the Company's

---

[581] Campbell Rebuttal at 3.
[582] *Id.* at 3-4.
[583] *Id.* at 4.
[584] *Id.* at 4-5.
[585] *Id.* at 5-6.
[586] Oliver Surrebuttal at 24.

application of 76% of the overall increase to non-residential rate classes, regardless of the ROR computed for those classes, to be inequitable and inappropriate.

Mr. Oliver contended that he did incorporate annualized authorized revenue, but just did not incorporate the differences between the Company's "Annualized Revenue at Current Rates" and its "Test Year Annualized Authorized Revenue" in the same manner as the Company chose to reflect those differences.[587] Mr. Oliver believed that treatment of the differences should be premised on class cost responsibilities, not just the Company's need to recover its overall revenue requirement.[588]

Mr. Oliver maintained that the Company's proposed adjustments to distribution charges do not reflect the rate impacts that customers in those classes have experienced.[589] Mr. Oliver noted that the magnitude of the Montgomery County Fuel and Energy Tax has increased significantly.[590]

e. <u>Staff's Surrebuttal to the Company</u>

The Company revised its revenue requirement. Consequently, as was reflected in Staff's Surrebuttal to the Company, Staff's revenue requirement increased, changing the rate class' UROR and individual bill impacts for most classes.[591]

3. <u>Commission Decision</u>

In rate design, we strive for a decent balance between the sometimes competing principles of cost causation, gradualism and overall fairness. Based on the record in this case, and consistent with our decision in the last Pepco rate case, we find that

[587] Oliver Surrebuttal at 25.
[588] *Id.* at 26.
[589] *Id.* at 27.
[590] *Id.* at 28.
[591] Campbell Surrebuttal at 1.

apportioning the revenue increase to the respective classes in accordance with a two-step allocation method initiates the best balance among applicable rate-making principles.

Given the revenue increase authorized in this case, we find a first-step allocation of 25% to under-earning classes, Rate Schedules R and RTM, is appropriate. We agree with the Company's proposal to not increase Rate Schedules MGT-3A, GT-3B, and TN because these schedules have URORs significantly above 1.0. We find acceptable the Company's proposed second step allocation of the remainder of the revenue increase amongst all customer classes (except MGT-3A, GT-3B, and TN) based on their level of current annualized distribution revenue.

We accept the Company's proposal to raise both the customer and volumetric charges of the R, RTM, and GS-LV rate classes equally, as well as the Company's proposal with respect to Rate Schedules MGT-LV, GT-LV, and GT-3A. Based on the authorized revenue increase in this case, as well as the rate design we adopt, the typical residential Standard Offer Service (SOS) customer using 1000 kWh per month[592] will see a total monthly bills increase of 2.20% or $2.42. Based on the approved changes in rates, the Company may adjust its revenue-per-customer levels in future BSA calculations.

E. <u>Grid Resiliency Charge (GRC)</u>

1. <u>Parties' Positions</u>

a. <u>Pepco</u>

Pepco proposed in this proceeding to undertake three defined projects aimed at increasing the reliability and resiliency of the Company's Maryland distribution system in an accelerated timeframe from 2014 through 2016. Pepco proposed to: (1) accelerate the capital investment and operations in the Company's priority feeder program; (2)

[592] Pepco is directed in future cases to provide mean and median usage figures for residential rate classes.

advance the four-year tree trimming cycle by trimming two years' of vegetation in 2014; and (3) perform selective undergrounding on six of the Company's distribution feeders most severely impacted during major storm events.

The Company proposed to pay for these accelerated projects by establishing a Grid Resiliency Charge ("GRC") that would act as a surcharge above base rates, enabling Pepco to recover contemporaneously the incremental capital costs and expenses associated with the acceleration of these three reliability projects. Specifically, the Company[593] claimed that the GRC "will enable Pepco to accelerate investment in infrastructure in a condensed time frame consistent with Recommendation Two of the GRTF Report."[594] In addition to the accelerated reliability project work and the GRC cost recovery mechanism, Pepco proposed a $1 million performance-based ratemaking incentive that would be provided to the Company if it meets certain metrics, or credited to the Maryland customers if the metrics are not met.

Company Witness Boyle testified that Pepco was prepared to accelerate the three projects to enhance service reliability and "to commit to enhanced reliability metrics predicated on its accelerated investment program."[595] Mr. Boyle testified that these accelerated expenditures are incremental to the Company's base capital and operating cost plans. He further explained that since Pepco is meeting its current reliability standards it will not perform the accelerated projects in the condensed timeframe absent the GRC.[596] Mr. Boyle noted that the GRTF acknowledged concern about the "undue financial pressure on the utilities" that voluntarily takes on an added level of investment

[593] Boyle Direct at 14.
[594] Pepco Application at 4.
[595] Boyle Direct at 13, 14.
[596] *Id.* at 14.

and therefore recommended that the Commission authorize contemporaneous cost recovery through a tracker-like[597] mechanism for accelerated investments to offset the added financial pressure.[598]

Mr. Boyle testified that the GRC Proposal "is designed to operate cohesively such that the accelerated reliability work, the cost recovery mechanism and the performance metrics are a non-severable package."[599] In response to other Parties' recommendations to remove certain components of the Company's GRC Proposal, Mr. Boyle stated that "it is important that the Commission understand that the Company proposed the accelerated investments and the accompanying Grid Resiliency Charge as an entire package."[600] He further warned that if the recommendations to remove various aspects of the Company's GRC Proposal were approved, then the Company would "reevaluate its voluntary proposal, with the potential determination that it cannot proceed with the accelerated investments under such terms and conditions."[601]

Mr. Boyle testified that approval of the GRC "in no way affects the Commission's ability or authority to conduct a prudence review of the Grid Resiliency Charge investments and expenses, and ... ultimately determine to exclude or reduce recovery for any item that the Commission deems imprudent."[602] Further, Mr. Boyle noted that Pepco would not oppose a Phase II of the present proceeding to further review the GRC

[597] "Tracker" is a term used by the GRTF and refers to a concurrent surcharge allowing a utility to begin recovering costs from its ratepayers immediately upon expenditure, rather than waiting until its next rate case. GRTF Report, p. 66.
[598] Boyle Direct at 14 citing Task Force Report at 80.
[599] *Id.* at 15.
[600] Boyle Rebuttal at 4.
[601] *Id.* at 5.
[602] *Id.* at 5.

Proposal "as long as that review does not result in a delay in the Commission's decision on the base rate application portion of this proceeding."[603]

Company Witness Gausman detailed the scope, cost and Company's rationale for each of the three GRC projects proposed. Setting the context for the Company's GRC Proposal, Mr. Gausman testified that the three accelerated projects chosen under the GRC were in line with the foundational principles set forth in the GRTF Report. Those foundational principles include the following:

1) "The current level of reliability and resiliency during major storms is not acceptable;
2) Increased reliability and resiliency is the goal of the Task Force and will inform its recommendations;
3) Severe weather events are likely to continue to occur and utilities, government and citizens must be prepared; and
4) If done strategically and appropriately, increased expenditures by utilities to improve resiliency and harden the grid will lead to fewer outages during storms and shorten outages when interruptions happen."[604]

Of the three projects recommended by the Company, Mr. Gausman stated that they "will increase the resiliency of the distribution system and 'accelerate RM 43's march toward reliability.' "[605]

First, Mr. Gausman discussed the work related to the Accelerated Priority Feeders. This project involves the Company's accelerating the hardening of an additional 24 feeders over two years, 12 feeders per year in 2014 and 2015.[606] Mr. Gausman clarified that these 24 feeders are in addition to the 55 feeders in the 2013 base construction plan (which includes 21 priority feeders and 34 Reliability Enhancement

[603] Boyle Rebuttal at 5.
[604] Gausman Direct at 19 (citing Task Force Report at 71) .
[605] *Id.* at 19-20 (citing in part GRTF Report at 72).
[606] *Id.* at 23.

Program (REP) feeders).[607] Mr. Gausman testified that the average cost associated with Priority Feeder work is $1 million per feeder; therefore, the Company estimated a capital investment of $12 million in 2014 and $12 million in 2015 for the Accelerated Priority Feeder work under the GRC Proposal.[608] The evaluation criteria for priority feeders chosen under the GRC Proposal include "outage data without exclusions for major events."[609] Mr. Gausman pointed out that the GRTF Report specifically supported the Accelerated Priority Feeder work by stating that "progress on some of Maryland's worse performing feeders has the potential to make meaningful difference in both actual interruptions and customer confidence."[610] The Company argued that "by remediating a total of 67 feeders in each of 2014 and 2015, Pepco will be addressing more than 9% of its approximately 700 Maryland feeders each year, for a total of 18% over the two year period."[611]

Second, Mr. Gausman described the Accelerated Vegetation Management (tree trimming) work being proposed under the GRC. The Company proposed to complete two years of the four-year cycle of vegetation management in 2014 allowing the Company to complete a full four-cycle of vegetation management ("VM") in 2015, one year in advance of the normal timeframe.[612] Mr. Gausman noted that the Company will perform the first year of a four year trim cycle in 2013. Figure 9 in Mr. Gausman's Direct Testimony showed that the estimated annual cost of vegetation management is $20.3 million. Since the Company GRC Proposal entails trimming an additional year of

[607] Gausman Direct at 23-24
[608] *Id.* at 24.
[609] *Id.* at24.
[610] *Id.* at 21 (citing Task Force Report at 77).
[611] Pepco Initial Brief at 70.
[612] Gausman Direct at 26.

vegetation management in 2014, Mr. Gausman estimated the additional cost for the accelerated tree trimming work in 2014 would be $17 million[613], almost all of which will be personnel costs. When cross examined on whether the Company had analyzed how much more reliable the system would be due to the vegetation management, Mr. Gausman conceded that the Company had not performed that level of analysis.

Third, Mr. Gausman discussed the Company's accelerated work related to selective undergrounding as part of the GRC Proposal. Pepco proposed to underground certain segments of six 13 KV distribution feeders with work to be performed between 2013 and 2016 and supported its proposal by the inclusion of a November 2012 Undergrounding Study attached as Schedule WMG-4 in Mr. Gausman's Direct Testimony. Using the data and findings in the Undergrounding Study, Mr. Gausman identified three of the six feeders in Montgomery County and another three feeders in Prince George's County for undergrounding. He estimated that the cost to underground these six feeders would be $151 million and projected that this investment would reduce the frequency and duration of outages by more than 99% compared to the portion of those feeders that are currently overhead.[614] He argued that the benefits associated with undergrounding could range from achieving as low as 7% improvement in reliability performance to 100% performance improvement, depending on the nature and amount of undergrounding.[615] However, Mr. Gausman admitted that "significant design and planning is required prior to beginning" this project after Commission approval, and Pepco would require the second six months of 2013 to plan the undergrounding work and

[613] Gausman Direct at 26.
[614] *Id.* at 28
[615] *Id.* at 27.

another three years to complete the construction work.[616] Additionally, Mr. Gausman acknowledged that the Company's undergrounding proposal does not address undergrounding 69kV substation supply lines which the GRTF Report highlighted, recommending that "any selective undergrounding or hardening scheme should give high priority to substation supply lines" because while they are relatively few in number, they accounted for 18% of the system interruptions in the three storms evaluated by the Task Force.[617]

Last, Mr. Gausman also addressed as part of the GRC Proposal specific performance metrics associated with these accelerated projects and the performance-based incentive proposal. The Company proposed specific system-wide SAIFI and SAIDI goals against which it would be measured.[618] The Company proposed that if it achieves a SAIFI performance of 1.25 and a SAIDI performance of 134 minutes, the Company would be permitted to collect a $1 million incentive through the GRC ($500,000 for meeting the SAIFI and $500,000 for achieving SAIDI).[619] Likewise, if Pepco's reliability performance of SAIFI is worse than 1.67 (measured on 2015 performance) and a SAIDI performance of 178 minutes (also measured on 2015 performance) then the Company would credit its customers $1 million through the GRC.[620] Mr. Gausman contended that this proposal was consistent with the Task Force Recommendation that the "Commission implement a ratemaking structure that aligns utility incentives by rewarding reliability that exceeds established metrics and penalizes

---

[616] Gausman Direct at 27.
[617] GRTF Report at 79.
[618] Gausman Direct at 28.
[619] *Id.* at 29
[620] *Id.* at 29.

for failure to reach those metrics."[621] The incentive or customer credit would be included in the GRC during 2016. Mr. Gausman asserted that the performance goals proposed by the Company, if achieved, would represent a "37% improvement in SAIFI and a 38% improvement in SAIDI from 2011 results."[622]

Concurring with Mr. Boyle, Mr. Gausman stated "that performing these [GRC] projects on the accelerated schedule is not included in the Company's scope of work to meet its SAIFI and SAIDI performance requirements under the Service and Quality Reliability Standards."[623] He further reiterated that, while the Company is prepared to perform these projects, it "cannot take on additional investment on top of the significant financial commitment that has already been made"[624] without approval of the GRC. Mr. Gausman argued that the projects under the GRC are consistent with the findings of the Task Force Report recommending that utilities should "temporarily go above and beyond their RM 43 requirements to jumpstart improvements so Marylanders can see real results in the next two years."[625]

In responding to several Intervenors who questioned whether the GRC projects met the GRTF designation as above and beyond, Mr. Gausman in Rebuttal Testimony offered that "VM is required by RM 43 to be performed on one quarter of the system per year, not one half as proposed in 2014, and the additional priority feeders are over and above the 3% required by regulation."[626] He further noted that each of the projects, if completed, would result in increasing the amount of work to be completed each year over

[621] Gausman Direct at 29 (citing Task Force Report at 80).
[622] *Id.* at 30.
[623] *Id.* at 21.
[624] *Id.* at 21.
[625] *Id.* at 21.
[626] Gausman Rebuttal at 12

the budgeted amount, and would advance reliability projects that could take several years to complete.[627]

Company Witness Janocha described the GRC tariff modifications and proposed cost of service and rate design related to the GRC. He testified that the GRC will be incorporated into the tariff through a new tariff rider (See Schedule JFJ-6) and would be in effect for approximately three years beginning January 2014.[628] The revenue requirement and resulting charge included in the GRC Rider would be calculated using projected cost data including, but not limited to: the actual cost of engineering; design and construction; the cost of removal (net of salvage) and property acquisition; and actual labor, materials, and capitalized Allowance for Funds Used During Construction (AFUDC).[629] The Company planned to track capital investments individually for each project through a separate CWIP account and record monthly accrual of AFUDC which will be included in the CWIP balance.[630]

Pepco proposed that the GRC be subject to deferred accounting with a monthly over/under recovery calculation performed based on actual revenues received under the GRC Rider and the actual revenue requirement in each month, and the over/under recovery will be tracked as a deferred balance.[631] In his Rebuttal Testimony, Mr. Janocha testified that the proposed deferred accounting mechanism adds a level of customer protection through which customers will ultimately have paid only for electric plant placed in service.[632] He explained that the GRC proposal included a final

[627] Gausman Rebuttal
[628] Janocha Direct at 11.
[629] *Id.* at 12.
[630] *Id.* at 12
[631] *Id.* at 12- 13.
[632] Janocha Rebuttal at 8.

reconciliation of the forecasted revenue requirement to the actual revenue requirement associated with plant placed in service. He further clarified that all investments associated with the GRC would be subject to prudency review in a future rate base distribution case and any costs disallowed will be reflected in the reconciliation process and customers would be appropriately credited.

In response to OPC's and Montgomery County's arguments that the use of projected costs for the GRC is analogous to a forecasted test year which the Commission has rejected in previous cases,[633] Mr. Janocha distinguished the GRC proposal from other surcharge and tracker type proposals rejected by the Commission in previous cases, including Case No. 9286 when Pepco proposed the Reliability Investment Recovery Mechanism ("RIM"). He asserted that the GRC "is intended to be a short term mechanism intended to recover costs associated with a specific limited group of projects" whereas the RIM was designed to be a more long term mechanism intended as an initial recovery mechanism for a wide range of reliability investments.[634]

Regarding cost allocation of GRC, Mr. Janocha testified that the total revenue requirement for the GRC would be allocated to each rate class on the basis of the rate class specific levels of non-customer related distribution revenue as approved in this proceeding.[635] For the Rate Schedules R, RTM, GS-LV, T, EV, SL, and TN, the GRC would be designed as a volumetric charge. For Rate Schedules MGT-LV, MGT-3A, GT-LV, GT-3A, and GT-3B, the charge would be designed as a demand charge applicable to the maximum monthly demand. For Rate Schedule TM-RT, the charge would be designed as a fixed monthly charge. For Rate Schedule OL, the charge would be

[633] Janocha Rebuttal at 7.
[634] *Id.* at 8.
[635] Janocha Direct at 13.

designed as a per lamp charge. Intervenors AOBA, GSA, and Staff raised concerns about the Company's proposed allocation of the GRC among rate classes. AOBA and GSA witnesses argued that the allocation should more closely follow cost causation and Staff witness recommended the Company allocate the revenue requirement based on the finalized unitized rates of return.[636] Mr. Janocha agreed that Staff's approach was a reasonable alternative and accomplishes the objective that the GRC revenues track distribution revenues.[637] He rebutted the proposals of AOBA and GSA contending that "[a] fully cost-based approach would be more appropriate if the surcharge were proposed as a permanent recovery mechanism, independent of base distribution."[638]

Mr. Janocha analyzed the bill impact of the GRC for all major classes in Schedule JFJ-8 of his direct testimony. As proposed, the GRC would go into effect on January 1, 2014 and was estimated to result in a rate increase for a typical residential customer using 1,000 kWhs per month of $0.96 or 0.64%.[639] In 2015 and 2016, the impacts are projected to be $1.70 or 1.13% and $1.93 or 1.28%, respectively.[640] Of the $0.96 GRC estimated to be recoverable in 2014 from a residential customer per month, $0.90 is attributed to vegetation management, $0.06 is attributed to priority feeders, and $0.00 is attributed to undergrounding in 2014 as charges for that component begins in 2015. Mr. Janocha, upon the Commissioner's bench request, provided charts showing the GRC impact by rate class and GRC component.[641]

---

[636] Janocha Rebuttal at 10.
[637] *Id.* at 10-11.
[638] *Id.* at 10.
[639] Janocha Direct at 15.
[640] Janocha Direct, Schedule JFJ-7 at 8.
[641] T at 897, L8- page 899, L6.

Mr. Janocha testified that "[t]he GRC would remain in effect until completion of the first rate case filed after all of the approved grid resiliency-related projects are placed into service." Intervenors OPC and MEA raised concerns the Company's proposal to terminate the GRC charge was not sufficiently definitive.[642] Mr. Janocha attempted to explain that the intent of the Company's approach was to ensure an appropriate transition of cost recovery from surcharge to base distribution rates that does not involve either a gap or redundancy in cost recovery.[643] Mr. Janocha also noted that the Company proposed to file an annual report by January 31 for each year the GRC is in effect (starting in January 2015).[644] Additionally, he indicated that the Company would perform a true-up reconciliation of the deferred GRC balance upon termination of the GRC charge.

b. <u>OPC</u>

OPC is wholly opposed to the GRC proposal. OPC witnesses Dismukes and Lanzalotta presented several arguments for rejecting the Company's GRC proposal.

Dr. Dismukes first argued that the Company's GRC proposal is premature because it identifies a number of reliability related investments for a new cost tracker mechanism "well in advance of any Commission findings regarding the appropriate level of resiliency that is needed in Maryland and the cost effectiveness of establishing a new standard."[645] Additionally, Dr. Dismukes noted that the Commission's recent Derecho Order outlined many of these steps and the timetable in which the steps should be performed. Dr. Dismukes cautioned that Commission approval of the Company's GRC

[642] Janocha Rebuttal at 8-9.
[643] *Id.* at 9.
[644] Janocha Direct at 13.
[645] Dismukes Direct at 3.

proposal would be the proverbial "cart before the horse" and should not be approved until the Commission's proceedings set out in the Derecho Order are complete.[646]

Second, Dr. Dismukes pointed out that the Company's GRC Proposal presented several inconsistencies with the GRTF Report which purportedly served as the basis for Pepco's overall GRC proposal. Specifically, Dr. Dismukes noted that the Company selected only a limited set of the GRTF Report recommendations to include in its GRC Proposal despite that the GRTF Report explicitly stated "if rolled out in an a la carte manner, [the recommendations] may not produce the expected results."[647] Dr. Dismukes further testified that the proposed performance-based ratemaking incentive mechanism is not tied to the Company's authorized rate of return, which was clearly included in the GRTF Recommendations noting "the preferred incentive ratemaking structure is one where "…the utility is penalized on its return on equity for failing to meet identified reliability metrics.""[648]

Third, Dr. Dismukes argued that the GRC Proposal should be rejected because it includes several design flaws. Those flaws include that: 1) the term (i.e., termination period) is ambiguous; 2) the revenue requirement will be developed on a projected rather than actual basis; 3) the Proposal does not explain how or when a prudence review will take place; 4) the annual reporting is insufficient; 5) the Proposal does not include ratepayer protections; and 6) there is no sunset provision.

Fourth, Dr. Dismukes argued that the Commission has addressed several infrastructure cost recovery mechanisms and similar proposals from various utilities over

[646] Dismukes Direct at 3.
[647] *Id.* at 4 (referencing the GRTF at 7).
[648] *Id.* at 5 (referencing the GRTF at 82).

the years. In each case, the Commission has rejected the infrastructure surcharge proposals.[649]

Finally, Dr. Dismukes noted that the GRTF Report was clear "that the only costs that will be eligible in any cost tracker mechanism are those that are BOTH accelerated and incremental, not just accelerated as the Company suggested."[650] Dr. Dismukes also argued that the Company's GRC Proposal does not take into account better RM 43 requirements, so it over-compensates Pepco for costs that are not incremental to the standard, and thus are not eligible for surcharge recovery.

Witness Lanzalotta, the engineering witness appearing for OPC, addressed several engineering reasons for rejecting the Company's GRC Proposal. Regarding the enhanced priority feeders component, Mr. Lanzalotta found that the 2011 priority feeders and the 2011 REP feeders experienced improved reliability <u>excluding</u> major storms since 2010. However, his analysis of SAIFI and SAIDI <u>including</u> major storms found that in 2012 both feeder groups maintained higher SAIDI values than those for Pepco's whole Maryland service area.[651] Mr. Lanzalotta concluded that the Company's reliability enhancement program for these two groups of feeders failed to achieve any improvement in their reliability performance during major storms.[652]

Next, Mr. Lanzalotta testified that Pepco had completed an accelerated vegetation trim of its entire system in 2011 and 2012. He concluded that for the Company "to engage in another accelerated round of tree trimming, immediately following the completion of an accelerated round of trimming will result in limited improvement at best

[649] Dismukes Direct at 6.
[650] *Id.* at 25.
[651] Lanzalotta Direct 15-16.
[652] *Id.* at 16-17.

in the resiliency of the Pepco system during major storms."[653] Under cross examination, Mr. Gausman testified that the Company's GRC vegetation management component does not propose standards beyond the current RM43 requirements and that the only change was to "speed up" the number of miles trimmed.[654] He also stated that the Company had not done any studies to determine the anticipated improvements in SAIFI and SAIDI due to the proposed accelerated tree trimming.

Last, Mr. Lanzalotta found several analytical weaknesses with the Company's Undergrounding Study. For instance, he found that the customer outage duration avoided by undergrounding various system components is subjective.[655] He further found that the Undergrounding Study failed to address how undergrounding one segment of the system will impact restoration times on other system segments.[656] Mr. Lanzalotta agreed that undergrounding overhead power lines will result in a "high level of protection" against weather conditions such as falling trees, wind, ice and snow. However, Mr. Lanzalotta testified that the project proposed by Pepco is not a cost-effective investment, since less than 2% of its entire system will be impacted for $151 million for six feeders. Mr. Lanzalotta further criticized the study for failing to consider several more undergrounding alternatives.

c. Staff

Staff witnesses partially support that the Commission approve of the Pepco's GRC proposal. Staff witness VanderHeyden testified that "Staff is willing to support a

[653] Lanzalotta Direct at 43.
[654] T at 491.
[655] Lanzalotta Direct at 30.
[656] *Id.* at 30.

limited GRC as a component of the recommendations of the GRTF Report."[657] Mr. VanderHeyden recommended the Commission permit the Company to recover a portion of resiliency expense and investment through a surcharge subject to the Commission's determination of its prudency following a review of a set of performance metrics including cost effectiveness.[658] However, Mr. VanderHeyden cautioned that "the use of non-traditional ratemaking methods should be introduced carefully and with clearly stated expectations for performance."[659] He also advised that the Company's GRC proposal be addressed in two separate issues: "1) whether the proposed projects to be covered by the GRC are prudent, cost effective and in the public interest, and 2) the manner in which Pepco should recover the costs of the projects."[660]

Specifically, Mr. VanderHeyden supported the recommendation of Staff witness Tucker who recommended approval of the Company's Accelerated Vegetation Management program and the Expanded Priority Feeder projects provided certain conditions are in place. With regard to the Accelerated Vegetation Management project, Ms. Tucker noted that even though Pepco has demonstrated "a history of missing its vegetation management goals," continuing in the direction of accelerated vegetation management pursuant Commission Order No. 84564 "until vegetation management goals have been met is prudent for increasing reliability across the Company's service territory." Ms. Tucker recommended approval of the Accelerated Vegetation Management program on the condition that Pepco provides a detailed report within 45 days of the completion of each year the vegetation management acceleration project. Ms.

---

[657] VanderHeyden Direct at 12-13.
[658] *Id.* at 4.
[659] *Id.* at 2.
[660] *Id.* at 14.

Tucker stated that the report should contain planned activities, time line, budget and detailed plan of how the Company will transition back to a four year trim cycle.[661] Staff also suggested that the Commission consider punitive monetary measures if Pepco fails to meet the Accelerated Vegetation Management project goals.[662]

Ms. Tucker also recommended Commission approval of the Expanded Priority Feeder Project on the condition the Company provides a report detailing the work performed and the budget for each feeder. As with the Accelerated Vegetation Management project, staff noted concerns with Pepco's budgeting and a timeline for project completion. Nonetheless, Staff testified that further expansion of feeder improvement, such as adding 24 feeders with specific focus of resilience against major outages, should improve Pepco's electric distribution reliability.[663] Staff asserted that the feeder program should improve Pepco's electric distribution reliability.[664]

Ms. Tucker testified that Staff could not recommend the proposed Selective Undergrounding project as a prudent expenditure under the GRC due to insufficient information specific to the six feeders proposed.[665] Specifically, Ms. Tucker argued that the Company "has not yet evaluated the potential for outage frequency on the six feeders in the proposal, once converted to underground."[666] Additionally, Ms. Tucker expressed concern about the high cost to Pepco's customers of undergrounding the proposed six feeders given that this project would benefit less than 1% of Pepco's customers.[667]

---

[661] Tucker Direct at 2.
[662] *Id.* at 8.
[663] *Id.* at 9.
[664] *Id.* at 9.
[665] *Id.* at 3.
[666] *Id.* at 11.
[667] *Id.* at 12.

Mr. VanderHeyden testified that he examined the GRC mainly from a policy and precedential perspective, and discussed whether the Commission should approve the GRC Proposal based on Commission precedent, legislation and the current regulatory environment.[668]

Mr. VanderHeyden testified that the Reliability Investment Recovery Mechanism requested by Pepco in its last rate case, Case No. 9286, has many of the same characteristics as the current GRC Proposal. However, the Commission in Order No. 85028 rejected RIM based on the following rationale:

> "…[C]onsistent with our decisions in every other case involving requests for infrastructure surcharges, [we] reject the Company's RIM proposal, especially since the reliability surcharge proposed will have very little to do with reliability. The Company is accountable to do what is needed to ensure continued safety and reliability of service to its customers….As we stated in Delmarva's last rate case, Case No. 9249 (Order No. 84170), more recently in the Washington Gas Light Company's rate case, Case No.9267 (Order No. 84475) and in BGE's Advance Metering Infrastructure case before that (Case No. 9208) we remain unpersuaded by the Company's arguments that we should deviate from historic rate making principles."[669]

Mr. VanderHeyden acknowledged that the Commission had not to his knowledge "reversed its position on this type of surcharge recovery for infrastructure. However given the concerns over recent severe weather events and the recommendations made by the GRTF, the Commission may wish to review the policy…"[670] Specifically, Mr. VanderHeyden highlighted the significant loss of electrical power and restoration time during the Derecho storm in June/July 2012. As a result of that storm, the Governor commissioned the GRTF. Additionally, Mr. VanderHeyden also noted that the Maryland

[668] VanderHeyden Direct at 4
[669] *Id.* at 6-7 (citing Order No. 85028).
[670] *Id.* at 7.

Legislature recently passed SB8/HB89, which allows the Commission to review an application for surcharge recovery of gas infrastructure outside a base rate case.[671] Finally, VanderHeyden cautioned that, given the Commission's recent Derecho Order in Case 9298, the best course of action for the Commission may be to wait and see the results of Case No. 9298 analysis prior to giving the go ahead to make resiliency investments independently and committing significant resources.[672]

d. AOBA

AOBA opposes the Company's GRC proposal and the Company's performance based rate making mechanism. Mr. Oliver suggested that the proposed incentive goal under the GRC is little more than the Company having the opportunity to earn back the penalty the Commission imposed on Pepco for reliability failings in Case No. 9240. Mr. Oliver recommended that Pepco should only be entitled to an incentive for "exemplary" performance, which would entail Pepco's reliability metrics exceeding those of its peers.

AOBA stated that "the Commission should be clear that [it] believes improvement of the resiliency of Pepco's distribution system is important and should be addressed on a priority basis. However, before approval of any element of that program is accepted, the Commission must address major shortcomings in the Company's proposals."[673]

AOBA noted that "the incremental revenue requirements for Accelerated Priority Feeders and Selective Undergrounding do not go away after 2016. Rather those revenue requirements continue for the life of the facilities installed"[674] and will be rolled into the

[671] VanderHeyden Direct at 8.
[672] *Id.* at 11.
[673] AOBA Initial Brief at 4.
[674] Oliver Direct at 22 fn 2.

Company's rate base when Pepco's next base rate case proceeding is completed. If the Company has not completed a new base rate filing prior to the end of 2016, the Company's proposal would allow Pepco to continue to recover those costs through the surcharge until the conclusion of its next base rate case.[675]

Regarding the Accelerated Vegetation Management project, Mr. Oliver questions the need for additional vegetation management and the Company's ability to perform the additional work according to the plan given their record of performance. Mr. Oliver testified that the Company did not identify any specific longer term benefits to be derived from the accelerated activity and, if the Company's vegetation management activities are up to date as reported by Mr. Gausman, then "there should be nothing substantial to be accomplished through the acceleration activities."[676] Additionally, Mr. Oliver pointed out that the Company was unable to complete all of its scheduled vegetation management activities for 2012 and that $1.8 million of those activities were deferred for completion in 2013. Further, he noted that if Pepco cannot complete one-year of a four-year vegetation management cycle within 2012, the Commission must question how it expects to accomplish two years of the same four year cycle within a single twelve month period.[677]

Regarding the Company's undergrounding proposal, AOBA argued that "undergrounding is but one means of hardening distribution system facilities, and at that, it is generally considered a very expensive alternative."[678] Mr. Oliver suggested that another option might involve the hardening of distribution poles while maintaining an

675 Oliver Direct at 22 fn 2.
676 *Id.* at 23.
677 *Id.* at 25.
678 *Id.* at 27.

overhead delivery system.[679] Mr. Oliver indicated that hardening the system in this way involved replacing wood poles with steel or concrete poles which are less susceptible to damage during storms.[680]

e. MEA

Maryland Energy Administration ("MEA"), through its witness Mr. Lucas, supported the Company's GRC Proposal with the exception of the undergrounding component, which MEA believes requires a more detailed analysis. With regard to undergrounding, MEA recommended that the Commission "should issue an order as soon as possible directing Pepco to promptly perform additional analysis in accordance with Staff's recommendations in order to have Pepco's undergrounding proposal considered for GRC cost recovery in a Phase II of this proceeding in time for construction to commence by 2014."[681]

Mr. Lucas supported the Company's GRC proposal primarily on the grounds that it was conceptually consistent with the GRTF Report. He argued that a tracker-type cost recovery mechanism allows for cost recovery more contemporaneously with investments than traditional ratemaking.[682] Mr. Lucas testified that MEA supports contemporaneous cost recovery to fund projects that will accelerate grid reliability over and above minimum regulatory standards, provided that there is Commission over sight and opportunity for consumer advocate and other interested stakeholder input.[683] He contended that because the Commission has established regulatory standards for vegetation management (RM43) and priority feeders, it will be able to measure whether

[679] Oliver Direct at 27.
[680] *Id.* at 27.
[681] MEA Initial Brief at 13.
[682] Lucas Direct at 3.
[683] *Id.* at 4.

Pepco's proposed projects in those areas are incremental or accelerated beyond what is necessary to meet the minimum requirements. Mr. Lucas noted that there are no specific regulations for undergrounding; thus making it harder to measure what is incremental or accelerated for that aspect of the GRC proposal.[684]

Mr. Lucas recommended that the Commission approve the GRC proposal, except for the performance based ratemaking component (or $1 million bonus/penalty). He advised that should the Commission approve the GRC its authorization should require that: 1) Pepco obtain pre-approval of the capital projects included in the GRC; 2) Pepco track early O&M savings due to increased reliability and resiliency and flow cost savings back to the ratepayers rather than be retained by shareholders; 3) the GRC have a sunset date since Pepco controls the timing of its future rate case filings; 4) commencement of the surcharge should not include advancing funds for work not yet completed; and 5) the Commission institute prudence monitoring of the GRC to ensure ratepayers dollars are being spent wisely.[685] With regard to the performance based ratemaking, Mr. Lucas found that it would be premature for the Commission to rule on that aspect of Pepco's GRC at this time in light of the Commission's Derecho Order directing Commission Staff to study performance based ratemaking.[686]

f. GSA

Witness Goins, testifying for GSA, opposed the GRC and the associated performance based ratemaking mechanism. Mr. Goins argued that Pepco has not provided sufficient evidence to support its claim that the surcharge is needed to avoid undue financial pressures. He asserted that the GRC shifts financial risk from Pepco

---

[684] Lucas Direct at 8-9
[685] *Id.* at 12-15.
[686] *Id.* at 3.

shareholders to its ratepayers, eliminates incentives caused by regulatory lag to lower costs and operate efficiently, and comes on top of Pepco's proposal to increase base distribution rates by 19.50% for residential customers in this case.[687] Mr. Goins objected to the Company's proposed volumetric rate design for the GRC arguing that it perpetuates interclass subsidies. Dr. Goins also believed that establishing an incentive mechanism is premature and should be rejected even if the Commission adopts the GRC. He suggested that the better course of action for the Commission is to wait until implementation of Case No. 9298.

g. AARP

AARP presented Witness Smith who opposed the Company's GRC Proposal. Mr. Smith testified that primarily he opposes the piecemeal ratemaking, surcharges and riders that seek recovery of costs outside traditional base rates, a concern that has been reflected in Commission decisions over the years.[688] Mr. Smith asserted that "[a] utility is obligated to provide reasonable service and to invest in the maintenance and reliability of its distribution system as a normal duty."[689] Traditional ratemaking permits utilities to seek rate recovery for investments and expenses incurred to meet its obligation assuming the costs are prudent.[690]

Mr. Smith argued that the Company failed to document adequate reasons why a specific rider is needed to continue its program of investments and tree trimming expenditures that are needed to deliver adequate and reasonable reliability of electric

[687] Goins Direct at 9.
[688] Smith Direct at 14.
[689] *Id.* at 14.
[690] *Id.* at 14.

distribution service. He also noted that the Company has not presented an adequate cost-benefit analysis to justify the proposed additional charges to ratepayers.[691]

Mr. Smith stated that the Commission should reject the entire proposal but, if the Commission is inclined to adopt some form of the GRC in the current rate case, an alternative would be inclusion of the cost for the Accelerated Priority Feeders component.[692]

h. Montgomery County

Witness Ostrander, testifying for Montgomery County, rejected the Company's GRC Proposal on several grounds. First, Mr. Ostrander contended that approval of the GRC does not follow Commission precedent for surcharges. Mr. Ostrander noted that the Commission has historically rejected surcharges related to advance recovery of projected capital costs even though the Commission has accepted other surcharges related to energy efficiency and demand response programs.[693] Namely, Mr. Ostrander pointed out the Commission's rationale for rejecting GRC type surcharges in the Case No. 9208, when the Commission rejected Baltimore Gas and Electric's (BGE's) proposed AMI surcharge. In Case No. 9208, the Commission reasoned that:

> "The programs for which we have approved surcharges, however, are fundamentally different in purpose and function than this Proposal. Neither energy efficiency nor demand response programs build utility infrastructure. The communications systems and load-control devices installed in connection with the Peak Rewards program, for example, serve only that specific program and have no other utility uses.
>
> Our other decisions allowing surcharges are consistent with this distinction. We also have approved surcharges to cover the costs of procuring Standard Offer Service ("SOS") electricity, the last vestige of supply-side costs we are obliged to allow in a

[691] Smith Direct at 14.
[692] *Id.* at 40.
[693] Ostrander Direct at 13.

> deregulated world. But we have rejected other requests to impose surcharges for non-infrastructure utility charges. For example, we rejected Delmarva Power & Light's request, in the context of its recent rate case, to remove the company costs for uncollectibles, pension and OPEB out of rates and into surcharges. We made there the same distinction we make here, defining in similar, core utility service terms the narrow range of circumstances in which surcharges are appropriate. We explained that "surcharges guarantee dollar-for-dollar recovery of specific costs, diminish the Company's incentive to control these costs, and exclude classic, ongoing utility expenses from the standard, contextual ratemaking analysis. We therefore limited this recovery mechanism to "very large, non-recurring expense items that have the potential to seriously impair a utility's financial well-being and that do not contribute to the Company's rate base" as opposed to "classic, ongoing costs of running a utility company."[694]

In contrast to the above referenced case of the Commission rejecting BGE's AMI surcharge proposal, Mr. Ostrander dutifully pointed out that the Commission has allowed surcharges related to energy efficiency and demand response programs and cited the Commission's approval of Pepco's and Delmarva's energy efficiency and demand response surcharge related to Empower Maryland Plan in Case No. 9155.

Mr. Ostrander also pointed out other examples of cases where the Commission has rejected surcharges related to advance recovery of projected capital costs. In Case No. 9286 decided in July 2012, the Commission rejected Pepco's proposed RIM finding that "[t]he Company is accountable to do what is needed to ensure continued safety and reliability of service to its customers"[695] and that the surcharge, whether RIM or GRC, will not solve the regulatory lag problem nor provide any quantifiable additional value to the ratepayers. In Case No. 9207, where DPL requested approval of an AMI surcharge,

---

[694] Order 83410, *In the Matter of The Application Of Baltimore Gas And Electric Company For Authorization To Deploy A Smart Grid Initiative And To Establish A Surcharge For The Recovery Of Cost,* Case No. 9208 (June 21, 2010) at pp. 28-29. (without footnote references) (emphasis added).
[695] Order 85028, *In the Matter of The Application Of Potomac Electric Power Company For Authority To Increase Its Rates And Charges For Electric Distribution Service,* Case No. 9286 (July 20, 2012) at pp. 143-144 (without footnote references).

the Commission "essentially denied the request for the surcharge by allowing Pepco and DPL to establish a deferred regulatory asset of the AMI costs offset by known and quantifiable AMI-related cost savings."[696] In Case No. 9267 decided in December 2011, the Commission rejected Washington Gas and Light Company proposed surcharge to recover capital costs related to Accelerated Pipe Replacement Plan (APRP) finding that "the Company has historically demonstrated the ability to replace its infrastructure when necessary to ensure safety and reliability and that it can do so with traditional ratemaking procedures without compromising its ability to earn an appropriate return."[697]

Second, Mr. Ostrander asserted that in the Derecho Order in Case No. 9298 (Order No. 85385) the Commission addressed resiliency and reliability concerns but indicated that there was no final decision on surcharge cost recovery. Mr. Ostrander also pointed out that in its Derecho Order the Commission directed utility companies to "conduct further studies and file short term plans by May 30, 2013 and longer term comprehensive reports by August 30, 2013" regarding various reliability investments and the costs versus benefits.[698] The Commission also directed Staff to draft proposed regulations revising sections of COMAR and to study and evaluate performance-based ratemaking by September 30, 2013.[699]

Finally, Mr. Ostrander provided a summarized list of the comprehensive historical arguments and rationale for rejecting capital recovery surcharges such as the GRC:

> "1) Pepco has not presented any new substantive and meaningful documentation that justifies a deviation from historical ratemaking principles. In addition, the GRC surcharge's advanced recovery of projected capital plant GRC is inconsistent with the

[696] Ostrander Direct at 17.
[697] *Id.* at 17-18.
[698] *Id.* at 10.
[699] *Id.* at 10.

Commission's precedent related to the "known and measurable" standard, whereby the Commission has historically rejected the inclusion in rate base of all projected plant additions beyond the hearing date in most recent rate cases involving WGL and BGE.

2) Pepco is already required to be accountable and take necessary actions to maintain existing safety and reliability standards, and Pepco does not provide adequate justification or any cost/benefit analysis to support a GRC intended to reflect accelerated plant investment aimed at achieving safety and reliability levels that exceed existing reasonable standards.

3) Pepco has not presented any new substantive and meaningful documentation to show that its financial situation justifies or compels implementation of a surcharge. Pepco can do the work it needs to do and have a reasonable opportunity to earn it approved return without any nontraditional recovery standards.

4) No new value is created by the GRC beyond accelerating Pepco's cost recovery, and Pepco has not provided any new substantive and meaningful documentation to show any additional value to parties of this proceeding, the Commission, and ultimately the ratepayers.

5) It will be difficult, if not impossible, to perform any type of meaningful prudence evaluation of capital assets recovered in advance from the GRC, because it will be difficult to disallow or reverse any significant construction after-the-fact, and once the GRC is in place it will be difficult to remove.

6) Pepco offers no new arguments to support any claims that the GRC is a reasonable response to regulatory lag, and the Commission indicates it has heard all of these same arguments before and there have not been any new arguments more compelling than others addressed in the past."[700]

2. Commission Decision

As far back as August 2010, the reliability and resiliency of Maryland's electric distribution infrastructure has been one of the major focuses of this Commission. Since then we have departed from our traditional ratemaking principles by allowing end-of-test year reliability plant and three month post-test year reliability spending adjustments in rate cases. In several of the rate cases since then we have been asked to approve a concurrent surcharge for proposed reliability projects, but to date we have found those

[700] Montgomery County Initial Brief at 13-14.

proposals lacking. Last year, following the power outages throughout the State caused by the Derecho storm, the GRTF appointed by the Governor recommended that such reliability spending surcharges may be appropriate. It is with this backdrop that we consider in this case Pepco's proposed Grid Resiliency Charge.

The Company has identified specific infrastructure improvements that would produce accelerated and incremental reliability benefits. These projects, by virtue of their incremental benefits, are designed to exceed the scope of the utility's plan to realize their RM43 annual performance standards. We find that a properly defined tracker proposal, when aligned with specific and measurable milestones and expenditures, can be appropriate to support the projects that are required to address the immediate challenges to improving reliability in Maryland. Although the proposals for trackers presented to us to date have been lacking in certain areas, the need for accelerated reliability work coupled with an aligned cost recovery mechanism is in our view justified, and indeed beneficial to ratepayers, under certain circumstances.

The GRTF Report stated that accelerated reliability cost recovery would be "exclusively for accelerated and incremental investments and expenses." Hence, a paramount question for us in deciding whether to grant the Company's GRC Proposal is whether, on this current record, we find that the proposed projects are accelerated and incremental to what is required to meet the current minimum reliability standards. And if so, the next question is whether the level of increased reliability and resiliency gained warrant a departure from Commission precedent.

In the case of the Accelerated Priority Feeders project, Company Witness Gausman stated that the priority feeders chosen under the GRC Proposal include "outage data *without exclusions* for major events." (emphasis added).[701] Currently, the Company takes corrective action on the poorest performing 3% of feeders, identified by a methodology that *excludes* major storm events. We find that the remediation to the priority feeders will provide cost effective incremental reliability benefits to the end users associated with feeders particularly prone to outages due to major storm events. The fact that this Accelerated Priority Feeders project includes 24 feeders *in addition to* the 55 feeders already in the 2013 base construction plan satisfies the acceleration component of the GRC.[702] Therefore, we approve the Company's GRC proposal with respect to the Accelerated Priority Feeders component, subject to the following conditions:

First, because this is a new tool we are considering undertaking for accelerated reliability work, we are obligated to the State and to the ratepayers to closely monitor the success and effectiveness of such a mechanism. To accomplish this, a tracker proposal must specifically identify a list of qualifying projects, a timeline, and interim milestones. The project descriptions must contain sufficient detail so as to track progress and related costs, and a commitment that any deviation from the project list requires further Commission approval. We recognize that the Company has supplied this information to some degree for the GRC. In this case, however, we direct the Company to provide additional detail for each feeder that includes the following: (1) a description of the proposed hardening work; (2) a performance objective for each project; (3) incremental milestones and estimated costs for each feeder project; and (4) estimated total costs.

Second, we also recognize that Company Witness Janocha laid the foundation for a detailed cost recovery mechanism and rate design in his discussion of a new tariff

[701] Gausman Direct at 24.
[702] *Id.* at 23-24.

rider.[703] We approve this methodology for calculating the revenue requirement and resulting charge under the GRC Rider. However, since we do not approve either the Vegetation Management or Selective Undergrounding components of the Company's GRC proposal at this time, we direct the Company to submit a revised calculation of revenue requirement to set the initial rates specific to the approved list of qualifying feeder projects as described by Witness Janocha.[704] We note that the GRC cost recovery in 2014 attributed to priority feeders is estimated to be $0.06 per month for a typical residential customer.[705] Given that the GRC would be limited in scope to the Accelerated Priority Feeders project, we decline to adopt the Company's proposed incentive structure.[706]

Third, we share the concerns and criticism by several of the other parties with respect to the lack of a sunset date and certain other consumer protection measures in the GRC proposal design. To this end, we direct the Company to submit a base rate case petition that aligns with the projected completion date of the qualifying projects, and stipulate that the qualifying projects and GRC revenues are subject to full review in the next base rate case following the completion of these projects. At that time, if the net capitalized amount of the qualifying projects is deemed reasonable and prudent, such costs will be rolled into the rate base resulting in termination of the GRC mechanism.

Lastly, we agree with concerns raised by several parties to the case that the Company's proposal in its current form does not contain assurances that expenditures

---

[703] Janocha Direct at 11.
[704] *Id.* at 12-13.
[705] Additionally, we estimate based on the rate of return authorized in this Order that the GRC for a typical residential customer in 2015 will be $0.19 per month and $0.27 per month in 2016.
[706] We acknowledge and agree with the GRTF finding that this type of ratemaking alternative should be directed at the utility's ROE.

will be just and reasonable. To this end, we direct the Company to provide an annual report to the Commission and Staff which includes: (1) the status of each project and respective milestones completed; (2) actual money spent to date on each project and respective milestone; (3) the reconciliation of projected costs and recoveries that includes a true-up calculation of over- and under- recoveries; and (4) a proposed rate for the GRC for the subsequent year, including bill impact estimates. Following the annual report submission, the Commission will issue an order to establish the Company's proposed new annual GRC adjustment for the following year.

With respect to the Accelerated Vegetation Management component, AOBA points out that "the proposed accelerated VM work would not reduce the need for on-going VM work under the standard four year cycle in future years."[707] We agree that the Company's plan for accelerating VM work in 2014 has no impact on the amount of tree trimming required for subsequent years and provides no cost savings in the future. Furthermore, given that Pepco has already completed an accelerated vegetation trimming of its entire system in 2011 and 2012, we agree with OPC Witness Lanzalotta that condensing the 2013-2016 tree trimming cycle into three years will only result in one-time limited benefits that do not warrant the expenditure of an additional $17 million. Therefore, we deny the Accelerated Vegetation Management component of the GRC.

Relating to the proposed selective undergrounding project, while we find that a mechanism such as the GRC may be appropriate, we agree fully with MEA and other parties in this case that the record is insufficient to justify its approval at this time, and more study is warranted. In order to consider such a proposal, we would require the Company to conduct its normal engineering review for each feeder proposed to be

[707] AOBA Initial Brief at 7.

undergrounded. Since undergrounding is the most expensive option available when considering resiliency improvements, the proposal should also include an analysis of effective alternatives. Finally, since the GRTF Report expressly stated that "any selective undergrounding or hardening scheme should give high priority to substation supply lines",[708] such an analysis should be part of the Company's proposal. Because the proposal for the undergrounding projects does not include such analyses, we deny this element of the GRC at this time.

In conclusion, we conditionally approve the Company's GRC proposal, limited in scope to its Accelerated Priority Feeders component. We also support the additional study of the proposed undergrounding project as recommended by MEA and Staff.

F. Miscellaneous

The record in this proceeding demonstrates that it was unnecessarily complicated by the parties' presentations. Company witness Hook alone filed testimony on six separate occasions. Additionally, AOBA moved to modify the procedural schedule in response to the Company's filing of its Supplemental Direct testimony, which the Commission denied in Order No. 85373.[709] However, the surprise filing of new NOLC issues in Ms. Hook's Supplemental Rebuttal testimony did result in a modification of the procedural schedule, which extended the date for the issuance of this Commission Order.

The Commission concludes that much of the disruption in these proceedings could have been avoided if the Company had not used six months of forecasted data in its initial Application. Providing eight months of actual data initially, thereby limiting the time required to update forecasted data for actual results, should enable parties to make

[708] Pepco Initial Brief at 70, citing the GRTF Report at 79.
[709] *See* Docket Entries 55 and 68.

more thorough and professional presentations and avoid many of the unnecessary disruptions experienced in this proceeding. Consequently, we direct Pepco in future rate case proceedings to limit its test year data to no more than four months of forecasted data.

IV. Conclusion

Based upon our review of the record in this case, we find that the Application filed on November 30, 2012, by Potomac Electric Power Company for a rate increase of $60,827,000 will not result in just and reasonable rates and is therefore rejected. Instead, we find that based on a test year of the twelve months ending December 31, 2012, as adjusted above, the Company is authorized to file revised rates and charges for an increase in revenues of $27,883,000, which amount will result in just and reasonable rates to the Company and its customers. As allocated, the increase in the overall residential bill will be approximately 2.19%, which is $2.41 per month on average. In addition, we conditionally approve the Company's GRC proposal, limited in scope to the Accelerated Priority Feeders component, effective January 1, 2014. The Company shall file revised tariffs for such increase in accordance with the rate design and other decisions in this Order.

IT IS THEREFORE, this 12th day of July, in the year Two Thousand and Thirteen, by the Public Service Commission of Maryland,

ORDERED: (1) That the Application of Potomac Electric Power Company filed on November 30, 2012, seeking to increase distribution rates for electric service by $60,827,000 in its Maryland service territory, is hereby denied.

(2) That Potomac Electric Power Company is hereby authorized, pursuant to § 4-204 of the Public Utility Companies Article, *Annotated Code of Maryland,* to file base rate tariffs for the distribution of electric energy in Maryland, which shall increase

rates by no more than $27,883,000, subject to paragraph (3) and which shall otherwise be consistent with the findings of this Order.

(3) That the Company's Grid Resiliency Charge proposal, limited in scope to the Accelerated Priority Feeders component, is approved subject to the conditions specified in this Order, effective January 1, 2014.

(4) That, except as provided in paragraph (3), such tariffs shall be effective for service rendered on and after July 12, 2013, subject to acceptance by the Commission.

(5) That all motions not granted herein are denied.

/s/ W. Kevin Hughes

/s/ Harold D. Williams

/s/ Lawrence Brenner

/s/ Kelly Speakes-Backman

Commissioners

Statement of Commissioner Lawrence Brenner
Concurring in Part

I write separately and briefly, on the matter of cost recovery for the accelerated priority feeders. I would have preferred setting up a mechanism similar to a deferred regulatory asset. That would have provided for a review, and a hearing, of the work done upon completion of each year's accelerated feeders before allowing the Company to recover its then-known and measureable reasonable, prudent costs. Also, given the relatively limited scope of the accelerated feeder work in each of two years, I would have allowed approved costs to be recovered by the Company after such a decision, without the need to wait for the next base rate case. My approach would have resulted in very little additional time than the GRC surcharge cost recovery treatment, as approved with conditions in this Order. However, it would have added the important safeguard, normally present in utility rate regulation for that very reason, of requiring Pepco to demonstrate that it had earned the right to recover its costs before it is handed the money. And, in the meantime, I would have granted the normal accounting treatment of allowing the Company to accrue its allowed rate of return on the deferred asset account.

I recognize the need to spur, incent, cajole, lead and when necessary, as it unfortunately has been, push and pull Pepco to improve its reliability. I believe my willingness to allow accelerated recovery for the accelerated feeders, if you will, without the need to wait for a full base rate case, would have been more than sufficient to provide prompt, reasonable recovery to Pepco, while better protecting customer ratepayers. And, in my view, Pepco's attitude about its GRC projects shows regrettably that it still doesn't get it. As cited in the main Order, Pepco's position is that unless it receives its requested GRC cost recovery treatment, it will not undertake the projects, and the projects are not separable – all or nothing, take it or leave it. My reaction to that is who is regulating whom here.

In this proceeding, Pepco has proposed what I think will be a good project to accelerate resiliency and reliability of priority feeders by cost-effective hardening of the feeders. If this project achieves its goals, it will be worthy of continuation in future years. But instead of leading the way to accelerate and expand its priority feeder work, Pepco carps that it is not required to include more than the 21 feeders per year (3% of the approximately 700 feeders on its Maryland system) plus the 34 Reliability Enhancement Feeders it previously proposed to do in 2013. The specifications and requirements of our reliability regulations and standards are the minimum of what should be done, not as Pepco seems to think the limit of its necessary efforts. Pepco should be the last company to think it is OK for it to remain among the laggards of the utilities, so long as it meets minimum specific work requirements. The bottom line should be for it to strive for top reliability performance in reducing frequency and duration of outages, to make sure it is well above the bottom performers. Instead of saying it would not do the accelerated feeder work without approval of all its proposed GRC projects, including undergrounding and accelerated tree trimming, and only with its proposed GRC surcharge treatment, Pepco should be proud and eager to roll out its well-considered accelerated feeder work to accelerate improvement of its past poor reliability.

In any event, if Pepco declines to perform the accelerated priority feeder project of an additional 12 such feeders a year in 2014 and 2015, because we are not approving the other GRC projects or because safeguarding performance and cost recovery conditions have been added in our Order, I would convene a proceeding to require Pepco to show cause why we should not order it done. This project not only has benefits of its own in the short-term, for a relatively small incremental average cost of $1 million per additional feeder, it could serve as a pilot to ascertain best practices for accelerating cost-effective hardening of many other feeders on the system.

I am concurring with the result reached in the Order on approval of the accelerated priority feeders to avoid a split Commission stalemate which would have had the result of not approving a project that I think is worthwhile, because of a disagreement over the cost-recovery mechanism. I think the safeguards put into place in the Order, while less than my approach would have provided, are adequate. My two colleagues with whom I concur in result on this matter have thoughtfully added requirements for up-front detailed descriptions of the work to be done, performance objectives for each feeder, incremental milestones and projected costs for each feeder and estimated overall costs. These items are further combined with an annual true-up reconciliation of projected and actual costs to yield the adjusted GRC surcharge for the following year, along with bill impacts. Also and importantly, the Order includes a sunset provision, requiring the Company to align the timing of filing a base rate case with the projected completion date of the accelerated feeders work. Thus the projects and GRC surcharge revenues will be subject to full base case review when finished, such that the GRC will end promptly on completion whether there will be disallowance or approval to roll the costs into rate base.

These conditions and the fact that the project at this time is limited in scope and time, with an estimated monthly residential bill impact of only 6 cents a month in 2014, growing but still relatively low to 19 cents in 2015 and 27 cents in 2016, have persuaded me to concur in the result.

/s/ *Lawrence Brenner*
Commissioner

Statement of Commissioner Harold D. Williams Dissenting in Part

Although I join the majority's Order in all other respects, I respectfully dissent from the majority's decision to allow cost recovery for the Accelerated Priority Feeder project by means of the Grid Resiliency Charge tracker mechanism. While I agree with my colleagues that the Accelerated Priority Feeder project has merit and, in theory, should result in some reliability improvement, I would provide for cost recovery for this project through a rolling two year regulatory asset. I continue to believe that the regulatory asset mechanism is an appropriate approach and join my colleagues who acknowledge its soundness by reaffirming today the prudently incurred costs precondition of the regulatory asset established in Order No. 83532. I cannot justify the fundamental shift from long-standing rate-making principles merely to enable Pepco to begin recovering the cost of this project from ratepayers even before the Company begins spending it. I continue to believe, as we wrote when we first considered a tracker surcharge for basic plant infrastructure, "We explained that 'surcharges guarantee dollar-for-dollar recovery of specific costs, diminish the Company's incentive to control those costs, and exclude classic, ongoing utility expenses from the standard, contextual ratemaking analysis.' We therefore limited this recovery mechanism to 'very large, non-recurring expense items that have the potential to seriously impair a utility's financial well-being and that do not contribute to the Company's rate base' as opposed to 'classic, ongoing costs of running a utility company.'"[710]

The GRC tracker is based on Pepco's estimates of what the costs *will be* to improve the Priority Feeders, a significant deviation from the historic ratemaking principle of "known and measurable," a principle we reiterate in this Order in denying Pepco's request to include a projected 9 months of future reliability expenditures. The GRC tracker requires ratepayers to pay for basic plant infrastructure before it is operable and providing any benefit to any of them. The GRC tracker also allows Pepco to collect from ratepayers $24 million before there has been any finding by the Commission that such expenditures were "prudently incurred." It will be months or even a year or more after the Priority Feeder work is completed before we can determine if that work has resulted in the increased SAIDI and SAIFI performance Pepco promises. While the conditions added by the majority, such as the requirement for specific reliability target metrics and an annual true-up, provide some limited ratepayer protections, in my view those conditions simply do not substitute for our traditional ratemaking protections. This Commission has never before allowed such a result for basic plant infrastructure.

Moreover, when Pepco finally does file a base rate case following the completion of the project and we do embark on a prudence review, Pepco will already have collected the $24 million. If it turns out that the Priority Feeder improvements do not meet the reliability standards they specified (and we approved), we will be faced with the prospect of having to "claw back" the money already collected and return it to the respective ratepayer classes. As we said regarding the proposed RIM tracker in Pepco's last rate

[710] *In the Matter of The Application of Baltimore Gas And Electric Company for Authorization To Deploy a Smart Grid Initiative And to Establish a Surcharge for the Recovery of Cost,* Case No. 9208, Order No. 83410, p. 29.

case, Case No. 9286, ". . . we suspect it will be difficult, if not impossible, for us to unpack *post hoc* any imprudence."[711]

Finally, as Montgomery County witness Ostrander pointed out, once tracker mechanisms are in place, they are difficult to remove.[712] The Maryland utilities have been asking us to approve tracker surcharges for reliability plant infrastructure for several years.[713] If we now deviate from our historic ratemaking principles and allow this GRC tracker, it will be difficult to find a principled way to deny future requests by other Maryland utilities for tracker surcharges for their similar reliability plant infrastructure projects.[714] I do not believe the short term benefit to the limited number of customers served by these 24 feeders is worth trading off the protections of traditional ratemaking principles for all utility ratepayers in Maryland for years to come. Today we are letting the tracker genie out of the bottle, and I fear it will continue granting the wishes of Maryland utilities for many years and we may never get it back in the bottle.

/s/ Harold D. Williams
Commissioner

[711] Order No. 85028 , p. 146.
[712] Direct Testimony of Bion C. Ostrander at 21.
[713] *See;* Case No. 9286; Case No.9267.
[714] Of course I reserve judgment on both the merits of future project proposals and their method of cost recovery.

APPENDIX I

POTOMAC ELECTRIC POWER COMPANY

CASE NO. 9311

Revenue Requirement
($000's)

Rate Base	1,183,052
Rate of Return	7.63%
Required Income	$90,267
Adjusted Income	$73,995
Income Deficiency	$16,272
Conversion Factor	1.71361
Revenue Requirement	$27,883

Rate Base
($000's)

Per Books Balance	$1,162,223
Uncontested Adjs.	(9,575)
Uncontested Balance	$1,152,648
Annualization of T-Y Reliability Closings	12,487
Actual Post-TY (Jan.-Mar. 2013) Reliability Closings	44,993
New Depreciation Rates	4,361
Amort. of 2012 Major Storm 6/29 Derecho	10,292
Amort. 2012 Major Storm – Hurricane Sandy	2,401
AMI Meters	(23,402)
Accenture Project	401
Adj. to Cash Working Capital	(21,129)
Adjusted Rate Base	1,183,052

Operating Income

($000's)

Per Books Balance	$66,548
Uncontested Adj.	668
Uncontested Balance	$67,216
Annualization of T-Y Reliability Closings	(748)
(Jan.-Mar. 2013) Reliability Closings	(580)
New Depreciation Rates	8,723
Amort. of 2012 Major Storm 6/29 Derecho	(2,287)
Amort. of 2012 Major Storm Hurricane Sandy	(534)
Uncollectible Write-Offs	(1,031)
3-Year Average AIP Costs	443
Current Rate Case Costs	(37)
Veg. Mgt. in Rate Period	$2,825
EA&EE	(989)
AMI Meters	542
Employee Activity Costs	89
Average Overtime Expense	$1,338
SERP	909
Outside Legal Expense288	
Accenture Cost239	
Amort. CN 9214 Expense	121
Operating Income Adjustments	9,311
Interest Synchronization	(55)
AFUDC Offset	(2,477)
Net Operating Income	$73,995

POTOMAC ELECTRIC POWER COMPANY
Analysis of Proposed Rate Increase - Position by Party
Twelve Months Ended December 31, 2012

As of 5/20/13

(Thousands of Dollars)

		Rate Base					Operating Income					Revenue Requirement				
		Pepco	Staff	OPC	Mont. Cty [5]	AOBA [3]	Pepco	Staff	OPC	Mont. Cty	AOBA	Pepco	Staff	OPC	Mont. Cty	AOBA
	Pepco Unadjusted Results, Based on Schedule (LJH-SR)-1	$ 1,162,223	$ 1,162,223	$ 1,162,223	$ 1,162,223	$ 1,162,223	$ 66,548	$ 66,548	$ 66,548	$ 66,548	$ 66,548	$ 46,485	$ 46,485	$ 46,485	$ 46,485	$ 46,485
	Ratemaking Adjustments															
	Uncontested Company-Proposed Ratemaking Adjustments:															
5	Annualization of 2011 Major Storm Amortization	(1,013)	(1,013)	(1,013)	(1,013)	(1,013)	(6,417)	(6,417)	(6,417)	(6,417)	(6,417)	10,856	10,856	10,856	10,856	10,856
8	Annualization of OPEB Medicare Subsidy Amortization	(68)	(68)	(68)	(68)	(68)	(80)	(80)	(80)	(80)	(80)	128	128	128	128	128
9	Annualization of MD Case No. 9286 Rate Increase	-	-	-	-	-	5,475	5,475	5,475	5,475	5,475	(9,382)	(9,382)	(9,382)	(9,382)	(9,382)
11	Annualization of Wage Increases	-	-	-	-	-	(1,544)	(1,544)	(1,544)	(1,544)	(1,544)	2,646	2,646	2,646	2,646	2,646
12	Reflection of 2013 Employee Health & Welfare Costs	-	-	-	-	-	(207)	(207)	(207)	(207)	(207)	355	355	355	355	355
14	Reflection of 3-Year Average Auto & General Claim Payments	-	-	-	-	-	10	10	10	10	10	(17)	(17)	(17)	(17)	(17)
15	Exclusion of Institutional & Promotional Advertising Expense	-	-	-	-	-	1,568	1,568	1,568	1,568	1,568	(2,687)	(2,687)	(2,687)	(2,687)	(2,687)
16	Exclusion of Executive Incentive Costs	-	-	-	-	-	2,690	2,690	2,690	2,690	2,690	(4,610)	(4,610)	(4,610)	(4,610)	(4,610)
17	Exclusion of Case No. 9240 Costs	-	-	-	-	-	5	5	5	5	5	(9)	(9)	(9)	(9)	(9)
18	Inclusion of Customer Deposit Interest & Credit Facility Expenses	-	-	-	-	-	(201)	(201)	(201)	(201)	(201)	344	344	344	344	344
19	Amortization of MD Case No. 9286 Rate Case Expense	-	-	-	-	-	(147)	(147)	(147)	(147)	(147)	252	252	252	252	252
22	Impact of Case No. 9286 Depreciation Rates on ITC Amortization	-	-	-	-	-	(512)	(512)	(512)	(512)	(512)	877	877	877	877	877
26	Remove NERC Expense Recorded in FERC Account 581	-	-	-	-	-	229	229	229	229	229	(392)	(392)	(392)	(392)	(392)
27	Reflection of Final Accounting Close	(5)	(5)	(5)	(5)	(5)	(201)	(201)	(201)	(201)	(201)	344	344	344	344	344
28	Inclusion of SERP Liabiilty, Net of Tax	(8,489)	(8,489)	(8,489)	(8,489)	(8,489)	-	-	-	-	-	(1,172)	(1,172)	(1,172)	(1,172)	(1,172)
	Contested Company-Proposed Adjustments:															
1	Annualization of Test Year Reliability Closings	$ 12,487	$ 12,487	$ 12,487	$ 12,487	$ 12,487	$ (748)	$ (748)	$ (748)	$ (748)	$ (748)	$ 3,006	$ 3,006	$ 3,006	$ 3,006	3,006
	Remove NOLC as Separate Adj. (Test Year)		$ (6,992)	$ (6,992)	$ (6,992)								$ (966)	$ (966)	$ (966)	
2	Inclusion of Post Test Year Reliability Closings (Jan - Mar 2013)	44,993	44,993	18,995	44,993	-	(580)	(580)	(312)	(580)	-	7,208	7,208	3,158	7,208	-
	Remove NOLC as Separate Adj. (Jan - Mar 2013)		(5,217)		(5,217)								$ (721)	$ -	$ (721)	
3	Inclusion of Post Test Year Reliability Closings (Apr - Dec 2013)	123,528	-	-	-	-	(1,215)	-	-	-	-	19,143	-	-	-	-
	Remove NOLC as Separate Adj. (Apr - Dec 2013)												$ -			
4	Annualization of New Depreciation Rates	3,538	3,538	4,361	4,084	3,538	7,077	7,077	8,723	8,168	7,077	(11,639)	(11,639)	(14,346)	(13,433)	(11,639)
6	Amortization of 2012 Major Storm Costs - June 29 Derecho	10,292	10,292	8,778	10,292	10,292	(2,287)	(2,287)	(1,350)	(2,287)	(2,287)	5,341	5,341	3,526	5,341	5,341
7	Amortization of 2012 Major Storm Costs - Hurricane Sandy	2,401	2,401	2,332	2,401	2,401	(534)	(534)	(316)	(380)	(534)	1,247	1,247	864	983	1,247
10	Reflection of Uncollectible Write-Offs	-	-	-	-	-	(1,031)	(1,031)	(1,065)	(1,031)	(1,031)	1,767	1,767	1,825	1,767	1,767
13	Reflection of 3-Year Average AIP Costs	-	-	-	-	-	443	443	1,925	443	443	(759)	(759)	(3,299)	(759)	(759)
20	Recovery of Current Rate Case Costs	-	-	-	-	-	(132)	(6)	(44)	(37)	(132)	226	10	75	63	226
21	Reflection of Vegetation Management in Rate Effective Period	-	-	-	-	-	2,588	2,825	7,466	2,588	2,825	(4,435)	(4,841)	(12,794)	(4,435)	(4,841)
23	Adjustment to Cash Working Capital Allowance	(7,109)	-	(7,109)	(7,109)	(7,109)	-	-	-	-	-	(982)	-	(982)	(982)	(982)
24	Tax Effect of Proforma Interest Expense [1]	-	-	-	-	-	1,912	525	(922)	1,912	1,912	(3,276)	(900)	1,580	(3,276)	(3,276)
25	Inclusion of Energy Advisors and Energy Engineers	-	-	-	-	-	(989)	-	-	(989)	-	1,695	-	-	1,695	-
	Contested Staff/Intervenor-Proposed Adjustments:															
	Remove Installed AMI Meters from Electric Plant In Service	-	(23,402)	(26,369)	-	(23,402)	-	542	538	-	-	-	(4,161)	(4,564)	-	(3,232)
	Remove Unadjusted Cash Working Capital	-	(22,186)	(15,077)	-	(22,186)	-	-	-	-	-	-	(3,064)	(2,082)	-	(3,064)
	Additional Reduction to CWC (Results in Negative Balance)	-	(46)	-	-	-	-	-	-	-	-	-	(6)	-	-	-
	Remove 50% of Employee Activity Costs	-	-	-	-	-	-	89	-	-	-	-	(153)	-	-	-
	Reflection of Accumulated Depreciation (Jan 2013 - Jun 2014)	-	-	(50,359)	-	-	-	-	-	-	-	-	-	(6,955)	-	-
	Reflection of Average Overtime Expense	-	-	-	-	-	-	-	1,369	1,338	-	-	-	(2,346)	(2,293)	-
	Remove SERP Related Expense	-	-	-	-	-	-	-	1,817	-	-	-	-	(3,114)	-	-
	Remove 50% of Directors & Officers Liability Insurance	-	-	-	-	-	-	-	134	-	-	-	-	(230)	-	-
	Remove 50% NOL Debit in Unadjusted Accumulated Deferred Tax	-	-	(42,700)	(42,579)	-	-	-	-	-	-	-	-	(5,898)	(5,881)	-
	Reduce Materials & Supplies Balance in Rate Base	-	-	-	(3,423)	-	-	-	-	-	-	-	-	-	(473)	-
	Reduce Outside Legal Expense	-	-	-	-	-	-	-	-	288	-	-	-	-	(494)	-
	Remove AMI Expense Potentially Included in Cost of Service	-	-	-	-	-	-	-	-	590	-	-	-	-	(1,011)	-
	Remove Accenture Expense for Sourcing & Procurement Project	-	-	-	401	-	-	-	-	239	-	-	-	-	(354)	-
	Amortize Case No. 9214 Expense	-	-	-	-	-	-	-	-	121	-	-	-	-	(207)	-
	Adjustment of Excess Long-Term Debt Costs										2,500					(4,284)
	AFUDC Offset [2]	-	-	-	-	-	(2,212)	(2,212)	(2,471)	(2,212)	(2,212)	3,791	3,791	4,234	3,791	3,791
	Adjustment to Reflect Staff/Intervenor Rate of Return	-	-	-	-	-						-	(8,610)	(10,086)	(1,991)	(17,136)
	Computational Issues with Income Tax Rates	-	-	-	-	-				188		-	-	-	(322)	-
	Rounding	-	-	-	-	-	-	-	-	1		-		4	(2)	-
	Total Revenue Requirement Based on Adjusted Results	$ 1,342,778	$ 1,168,516	$ 1,050,995	$ 1,161,986	$ 1,128,669	$ 69,508	$ 71,319	$ 81,960	$ 74,828	$ 75,029	$ 66,351	$ 30,568	$ (5,372)	$ 30,272	$ 10,183
	Revenue Gross Up Factor:	58.3563%									Company Requested Revenue Requirement	$ 60,827				
	Taxes:	59.6359%														

Appendix II

POTOMAC ELECTRIC POWER COMPANY
Analysis of Proposed Rate Increase - Position by Party
Twelve Months Ended December 31, 2012

As of 5/20/13

Overall Rate of Return:

	Pepco	Staff	OPC	Mont. Cty	AOBA [4]
Long Term Debt	3.05%	3.05%	3.05%	3.29%	2.868%
Short Term Debt	0.00%	0.00%	0.00%	0.00%	0.025%
Common Equity	5.01%	4.58%	4.45%	4.67%	4.281%
Total	8.06%	7.63%	7.50%	7.96%	7.174%

[1] Note that Montgomery County did not reflect the corresponding impact to interest synchronization for its proposed adjustments to rate base. Adjusting for such would result in a reduction to operating income and an increase to revenue requirement.
[2] Note that Staff and Montgomery County did not reflect the corresponding impact to AFUDC for their proposed adjustments to rate base. Adjusting for such would result in a reduction to operating income and an increase to revenue requirement.
[3] AOBA supports Staff's positions on Removal of Costs for Installed AMI Meters, Unadjusted CWC, and Vegetation Management for the Rate Effective Period; AOBA supports exclusion costs for of post-test year reliability closings.
[4] Includes consideration of Pepco's end-of-test year short-term debt balance, Pepco's March 11, 2013 bond issuance, and the $175 million additional equity contribution from PHI on March 28, 2013.

AOBA Recommended Capital Structure and Cost Rates

Type of Capital	Amount (in Millions)	% of Total	Cost Rate	Weighted Cost Rate	
LTD	1,900,767	48.12%	5.96%	2.868%	
STD	231,000	5.85%	0.43%	0.025%	
CE	1,818,194	46.03%	9.30%	4.281%	
Total	3,949,961	100.00%		**7.174%**	Overall Rate of Return

[5] Note that there are adjustments proposed by other intervenors in this proceeding that Montgomery County does not oppose which will be reflected in an exhibit to its Initial Brief.

Grid Resiliency Charge

	Pepco	Staff	OPC	Mont. Cty	AOBA	AARP	MEA	GSA
For	X	X					X	
Oppose			X	X	X	X		X

BEFORE THE PUBLIC SERVICE COMMISSION
OF
THE STATE OF MISSISSIPPI

MISSISSIPPI POWER COMPANY **DOCKET NO. 01-UN-0548**

IN RE: NOTICE OF INTENT OF MISSISSIPPI POWER COMPANY TO CHANGE RATES FOR ELECTRIC SERVICE IN ITS CERTIFICATED AREAS IN THE TWENTY-THREE COUNTIES OF SOUTHEAST MISSISSIPPI

FINAL ORDER

COMES NOW, the Mississippi Public Service Commission (Commission) and issues the following Final Order in this cause.

I. INTRODUCTION

MPCo is a public utility as defined in Section 77-3-3(d)(i) of the *Mississippi Code of 1972, as amended*, and is engaged in the business of generating, transmitting and distributing electric power to and for the public for compensation in twenty-three (23) counties of southeast Mississippi, having its principal place of business at Gulfport, Mississippi. The Company's mailing address is Post Office Box 4079, Gulfport, Mississippi, 39502-4079.

MPCo is the holder of a Certificate of Public Convenience and Necessity issued in Docket No. U-99, as supplemented from time to time, authorizing its operations in specified areas of the twenty-three (23) counties of southeast Mississippi and is rendering electric service in accordance with its service rules and regulations and in accordance with schedules of rates and charges, all of which are a part of its tariff that has been previously approved by order of this Commission.

MPCo is a Mississippi corporation. A copy of its corporate charter, articles of incorporation, the names and addresses of its board of directors and officers, and the name of all persons owning fifteen percent (15%) or more of its stock arc on file with this Commission.

MPCo has, since 1986, operated under a Performance Evaluation Plan Rate Schedule designated variously, as revised and amended from time to time, as PEP, PEP-1, PEP-1A and PEP-2. MPCo is authorized under PEP-2 to file a rate proceeding to adjust its rates when there is major construction, purchase, or modification of plant such as occurred with the new Victor J. Daniel Generating Plant Units 3 and 4, the construction of which were authorized by this Commission in Docket No. 97-UA-496. The units were placed in service in May and April of this year, respectively.

II. PROCEDURAL HISTORY

On August 3, 2001, pursuant to PEP-2, Mississippi Power Company, Inc. (MPCo) filed its Notice of Intent ("Notice") to change its rates for electric service, presently on file with the Commission, to be effective with the first billing cycle of January 2002, for bills rendered on and after such date. In its notice, MPCo requested an increase in rates of approximately 9.5% for the average retail customer.

The Commission entered a suspension order in this docket on August 3, 2001, requesting the Public Utilities Staff (Staff) to conduct a full investigation of the lawfulness of the proposed rates and charges contained in MPCo's notice. On August 7, 2001, the Commission issued an order suspending PEP-2 (Docket 93-UA-302) until a final order was issued in the proceeding at hand or until further Order of the Commission.

Notice of the filing was given as required by law and this Commission's Public Utilities Rules of Practice and Procedure ("Rules") to all persons who were parties of record in the

Company's last proceeding in which a major change in rates was sought, to certain other interested persons, and by publication on August 8, 2001, in the *Clarion Ledger* and in the *Sun Herald*.

A Scheduling Order was issued on August 14, 2001, establishing procedures for the timely resolution of this matter within the 120 day period prescribed by Mississippi law, including establishing intervention procedures, discovery procedures, deadlines for the filing of testimony, pre-hearing conferences, and setting his matter for hearing November 7-9, 2001.

The Intervenors in this filing were: Colonial Pipeline Company ("Colonial"); Mississippi Manufacturers Association ("MMA"); Federal Executive Agencies, by and through the Department of the Navy ("NAVY"); Williams Energy Marketing and Trading Company ("Williams"); Mississippi Casino Operators Association d/b/a Gulf Coast Gaming Association ("GCGA"); Mississippi Chapter of the National Federation of Independent Business ("NFIB"); Sierra Club, Mississippi Chapter ("Sierra"); Dynegy, Inc. ("Dynegy"); and Chevron USA, Inc. ("Chevron"). Colonial withdraw its intervention on November 6, 2001. The Staff participated as a party litigant. Each intervenor had a full opportunity for discovery in the period established in the Scheduling Order.

The Commission's Scheduling Order provided that all data requests were to be propounded no later than September 28, 2001. During the discovery phase of this proceeding, various parties propounded to MPCo approximately 420 data requests, which included sub-parts amounting to more than 1000 requests, covering all aspects of MPCo's filing and its operations. The Staff propounded 195 data requests, GCGA propounded 210 data request, MMA propounded 14 data requests and the Navy propounded 1 data request. No motion was filed with the Commission by any party as to the sufficiency of the responses provided by MPCo or any other party.

MPCo requested a waiver of the requirements of Miss. Code Ann., Section 77-3-37(4) (2000). On August 24, 2001, GCGA filed a Motion in Opposition to MPCo's request for waiver of these requirements. On September 18, 2001, MPCo renewed its request for waiver of the requirements of Miss. Code Ann., 77-3-37(4) (2000). MPCo filed a lead-lag study on September 18, 2001.

A pre-hearing conference, scheduled by order of this Commission, was convened on October 18, 2001, in the hearing room of the Commission. The Honorable Bruce McKinley was designated by the Commission to conduct the hearing. All of the intervenors in this docket, except the Navy and NFIB, appeared and participated in the pre-hearing conference along with the Staff and MPCo. At the pre-hearing conference, discussions and information were exchanged by and among the parties in attendance. At the recommendation of Mr. McKinley and by agreement of the parties in attendance, the pre-hearing conference was recessed until November 6, 2001 at 9:00 a.m. (CST). However, the parties were encouraged by Mr. McKinley as authorized by law to enter into stipulations notwithstanding the fact that the original pre-hearing conference was recessed. On October 26, 2001, the Staff and MPCo entered into a Stipulation. The pre-hearing conference was not reconvened on November 6, 2001, after the parties acknowledged that no additional stipulations had been reached between any other parties.

Sierra pre-filed the direct testimony of Becky Gillete and Aaron Viles on October 18, 2001. the Navy pre-filed the direct testimony of Dr. John B. Legier, MMA pre-filed the direct testimony of R.G. McBride and Roland Woodard, GCGA pre-filed the direct testimony of James

R. Dittmer, and the Staff pre-filed the direct testimony of Dr. Christopher Garbacz on October 22, 2001.

On October 26, 2001, the Staff and MPCo filed a Stipulation in this docket addressing various issues presented in the Company's filing. Among other things, the Staff and Company stipulated that the Company's filing was made pursuant to the authority of PEP-2; that the Company's filing satisfied the filing requirements of Mississippi law and this Commission's Rules; that the Company's jurisdictional cost of service allocations are just and reasonable; that adjustments and/or reductions should be made to the Company's test year rate base and expenses; that the Company's test year capital structure and weighted cost of Debt, Trust Preferred Stock and Preferred Stock portions of cost of capital are appropriate, just and reasonable; that certain changes to PEP-2 are desirable; that the Company's request in this docket, as modified by the Stipulation should be approved; and that the changes to PEP-2 proposed in the Stipulation would result in the performance evaluation plan reflecting and producing rates that are just, reasonable, and in the best interest of the customers and the Company. The particular provisions of the Stipulation related to rate base and expense adjustments, cost of capital, and the refinements to PEP-2, and this Commission's findings with respect to those matters so stipulated are addressed in the Findings and Conclusions section of this Order.

On October 30, 2001, this Commission issued an order, *sua sponte*, which recognized the need for incorporating the findings and conclusions of this docket into PEP-2 and that such incorporation would allow for the orderly transition from rate case back to the normal operation of the PEP-2 rate. The order further authorized and directed the parties of record to submit such additional testimony or evidence as they deemed appropriate to address any issues raised by the incorporation of the rate case conclusions into PEP-2 and by the re-activation of periodic evaluations under PEP-2. In response to this Commission's October 30 order, GCGA filed a motion asking this Commission to withdraw or modify that order. Oral arguments on GCGA's motion were held on November 6, 2001, at which time counsel for GCGA, MPCo, MMA and MPUS appeared and presented arguments regarding GCGA's motion and this Commission's October 30th order. That motion was overruled by the Commission.

On November 6, 2001, the Commission issued a Procedural Order establishing the procedures, including the order of presentation of witnesses and cross-examination for the upcoming hearings.

On November 6, 2001, the Staff filed supplemental testimony of Dr. Christopher Garbacz and MPCo filed supplemental testimony of Dr. Roger A. Morin, along with rebuttal testimony of H.E. Blakeslee, Frances Turnage and Charles a. Benore in accordance with the Commission's October 30, 2001 Order.

III. JURISDICTION AND SUFFICIENCY OF THE FILING

This Commission has jurisdiction of this matter by virtue of its subject and the authority conferred upon this Commission by the laws of the State of Mississippi.

This Commission finds that the pleadings, testimony, data, documentation and exhibits to this docket filed by MPCo comply with all the statutory filing requirements and the requirements of the Commission's Rules for major changes in rates in excess of $15 million, except the requirements of Miss. Code Ann. 77-3-37(4) (b), (c) and (d) (2000), which this Commission finds inapplicable and hereby waives.

This Commission further finds that the Stipulation entered into between the Staff and the Company and filed with this Commission complies with this Commission's Rules and Mississippi law.

Hearings in his docket were held on November 7-9, 2001 in the hearing room of the Commission.

IV. FINDINGS AND CONCLUSIONS

A. STIPULATION.

As stated previously, on October 26, 2001, the Staff and Company filed a joint Stipulation addressing numerous issues related to the Company's filing, including the incorporation of those agreements into PEP-2. As part of its investigation of this request, the Staff undertook a careful and thorough examination of the Company and its business operations. The Staff propounded and the Company responded to 195 data requests, many of which had multiple subparts. The Staff also reviewed the Company's responses to other parties' data requests. Additionally, the Staff had the benefit of conducting regular audits and reviewing the Company's books and records in connection with PEP and other rate filings. This experience gives the Staff a unique insight into the Company's finances and operations. Based upon the Staff's review, it entered into the Stipulation. The Staff recommended approval of the Company's request subject to several changes. This Commission has carefully reviewed the Stipulation and finds that there is substantial evidence in the record to support the Stipulation. This Commission finds that the Stipulation and the matters contained therein are just and reasonable, will benefit retail customers and will reduce the impacts of the Company's request on such customers. Therefore, this Commission hereby adopts the Stipulation dated October 26, 2001, and incorporates the Stipulation herein by reference. Specific findings regarding certain

Stipulation recommendations will be addressed later in this order, including findings regarding recommendations by intervenors which are contrary to the terms of the Stipulation.

1. Jurisdictional Allocations.

As noted in the Stipulation, the Company's proposed change in rates is based upon a jurisdictional cost of service study. This study was offered by Ms. Donna H. Van Loon. After careful review of the study and its allocations, the Staff and MPCo stipulated, and this Commission specifically finds, that the study and its jurisdictional allocations of expenses, revenues and rate base are just and reasonable and shall be used in this proceeding and other proceedings where such allocations must be made.

2. Rate Base Items.

The Company's filing also contains information related to the Company's rate base, revenue, and expenses for the historic year, 2000, as well as projections of rate base, revenues, expenses and cost of capital for the pro forma test year, 2002. That information was presented in the pre-filed testimony and exhibits of Ms. Van Loon, Ms. Frances Turnage, and Mr. Charles Benore.

The Company filed and proposed a retail average rate base of $753,184,879, for the pro forma test year. The Staff recommended a reduction of $21,435,744 to the Company's pro forma retail average rate base. With that adjustment, the Staff and Company have stipulated to an adjusted rate base of $731,749,135 for the pro forma test year, which this Commission finds to be just and reasonable and hereby adopts.

The Stipulation made specific recommendations regarding the treatment of certain rate base items:

a. Cash Working Capital: In its original filing, the Company calculated a value for cash working capital by taking one-eighth of its non-fuel operation and maintenance expense. This formula is commonly referred to as the "45-day formula." The 45-day formula resulted in a retail cash working capital calculation of $22,593,980. The Company later filed a lead/lag study that indicated a cash working capital calculation of $14,030,903. PEP-2 includes a cash working capital value of negative $5,500,000. The Staff and Company agreed and stipulated to the use of a $0 (zero) retail cash working capital value. Mr. Dittmer, a witness for GCGA, in his testimony adjusted the Company's lead-lag study to eliminate non-cash items. His calculation indicated that the Company's cash working capital requirements are approximately $638,729. Mr. Dittmer then suggested that cash working capital be set at a negative number, but those suggestions were not based on any substantial evidence. No other intervenor gave a recommendation or opinion on this issue. This Commission recognizes that determining the proper amount of cash working capital is not susceptible to exact measurement, but the preponderance of evidence offered indicates that the Company's cash working capital is greater than zero. Therefore, this Commission finds, based upon the various amounts calculated by the parties, that the stipulated retail cash working capital value of $0 (zero) is appropriate and is adopted for inclusion.

b. Construction Work in Progress: In its original filing, the Company proposed that 100% of the Company's average balance of construction work in progress ("CWIP") be included in rate base. The Company asserts that an on-going construction program is required to meet its customers' needs for reliable service. The Staff and Company have agreed and stipulated that the Company's average CWIP balance for all projects ending within one year of the end of the test period shall be included in rate base with any related allowance for funds used during construction ("AFUDC") accrued by the Company included in operating income. Mr. Dittmer was the only other witness to address this issue. He testified and proposed that this Commission change its long-standing position on construction work in progress by not allowing any construction work in progress to be included in rate base. Mr. Dittmer suggests that the Company will be compensated appropriately by virtue of its use of AFUDC. However, this Commission finds that an on-going construction program is necessary for Mississippi Power Company to meet the needs of its customers, particularly in light of our emphasis on improving reliability and customer service. Moreover, this Commission agrees with Ms. Turnage that greater use of AFUDC could ultimately lead to higher costs for customers. Therefore, this Commission finds that the Staff's and Company's stipulated position on construction work in progress is appropriate and is adopted for inclusion.

c. Regulatory Asset Over/Under Recovery of Ad Valorem Taxes: For purposes of determining operating income and rate levels in PEP-2, the Company accrues its ad valorem tax expense throughout the year for which the tax assessment is made. A portion of ad valorem tax expense is recovered during that year in base rates. The remainder is collected the following year, after the taxes are paid, through the operation of the ad valorem tax adjustment clause (ATA). Because rate base and assessed property values increase over time and because of the mechanics of ATA, this balance is a growing under-recovery. The deferred amount (ad valorem tax under-recovery) has grown over the years to a projected average balance of over $8 million. This represents a substantial commitment of capital. The Staff and Company have stipulated and this Commission agrees and finds that it is appropriate to include the amount of this under-recovery in the determination of retail average rate base. No intervenor has objected to or proposed an alternate treatment of this regulatory asset.

d. Property Damage Reserve: This Commission has allowed the Company to accrue a storm damage reserve (a.k.a. property damage reserve) to prepare for the damages caused by natural disasters that occasionally affect the Company's facilities. Recently, this Commission issued an order in Docket No. 99-UN-497 that provides the Company with flexibility to adjust its accrual amount as the Company deems appropriate up to $4.5 million. The Company and Staff have agreed and stipulated that, as part of the adjustments to rate base, the Company would modify downward the amount for storm damage reserve expense accrual in its rate calculation for the test period and that the Company should continue to comply with this Commission's storm damage reserve order. This Commission finds that the reduction of the storm damage reserve accrual in the test year and the continued compliance with this Commission's order is just and reasonable.

3. **Revenues and Operating Expense Items.**

a. Adjustments to Expenses: The Company filed and proposed projected revenues and projected expenses which would result in retail net operating income of $76,034,767 in the 2002 test year. The Staff carefully reviewed and considered the Company's testimony and exhibits as they relate to various expense items. The Staff, as stated in the Stipulation, has carefully considered all of the information provided to the Staff and to other intervenors in response to all data requests in this proceeding, particularly with regard to the information provided on the Company's estimations of expenses for the Company's retail electric operations. The Staff has recommended, and Company has agreed, to a reduction in the Company's projected expenses in 2002 of $865,563, including the effect of income taxes. Mr. Dittmer was the only witness who suggested specific recommendations for adjustments to the Company's expenses, including recommendations to adjust outage expenses, labor expenses, capacity equalization calculations, and revenues for off-system sales. However, some of the adjustments proposed by Mr. Dittmer were not based upon substantial evidence and others were based on incorrect assumptions. First, Mr. Dittmer recommended that this Commission reduce outage expenses at generating units by approximately $2.2 million in retail expenses in the test year based upon his normalizing those major outage expenses for a five-year average. However, the Company correctly pointed out that Mr. Dittmer's adjustment focuses on only the production component of the Company's total operations and maintenance cost. We are not persuaded by Mr. Dittmer's selective adjustment to the Company's operations and maintenance expenses. This Commission must consider all of the Company's operations and maintenance expenses to determine if the overall expenses are reasonable. When viewed in their totality, the Company's operations and maintenance expenses, as adjusted by the Stipulation, are reasonable.

Second, Mr. Dittmer recommended that this Commission eliminate from the Company's projected expenses the costs of establishing a Regional Transmission Organization ("RTO"). This Commission is well aware of the Federal Energy Regulatory Commission's recent attempts to form RTOs. If Southern Company and its operating companies are required to begin the process of forming an RTO in 2002, which is very likely based upon our own involvement in that process and based upon the testimony of Mr. Blakeslee, the Company's projected $1 million probably understates the actual costs to MPCo's retail operations in 2002.

Third, Mr. Dittmer proposed an adjustment to payroll/labor costs in 2002. The Company's witness, Ms. Turnage, addressed Mr. Dittmer's proposal and demonstrated that the Company's filed labor costs are just and reasonable. Therefore, this Commission rejects Mr. Dittmer's proposal to reduce labor costs.

This Commission has long encouraged the parties to try to resolve all reasonable issues, and for this reason, this Commission requires that pre-hearing conferences be held in these cases. Several witnesses indicated that the adjustment to expenses was a "settlement" of disputed issues related to expenses. This Commission realizes that the Staff and utilities routinely disagree over the treatment of expense items, and finds that the adjustment agreed to in the Stipulation is reasonable in light of the extensive knowledge the Staff has regarding the Company's operations and the overwhelming amount of discovery produced by the Company in this proceeding.

The Staff will again have the opportunity to review the Company's 2002 expenses and to propose adjustments to those expenses in connection with the Company's PEP-2 evaluation for the twelve-month period ending December 31, 2002. This evaluation will review twelve months of historical or actual expense information, which is the same period as the projected period in this filing which was prepared using projected 2002 figures. For the foregoing reasons and based upon this Commission's treatment of the specific adjustments suggested by Mr. Dittmer, this Commission finds that the proposed expenses as adjusted by the Stipulation are just and reasonable and, when considered along with the other findings of this Commission, will result in just and reasonable rates and we hereby adopt same.

b. Adjustments to Revenues: Mr. Dittmer recommends that this Commission make an adjustment to the Company's projected off-system sales revenues for 2002. Mr. Dittmer proposes to increase the projected revenues from off-system sales by approximately $8.1 million. Mr. Dittmer admitted however, that his adjustment was based upon the assumption that the Company should be in a better position to sell capacity off-system in 2002 than it was in 2001. Mr. Dittmer apparently did not consider the fact that the Company had been purchasing significant amounts of capacity and energy prior to the completion of Daniel Units 3 and 4, and that these purchases were replaced by those units. Mr. Dittmer did not undertake any evaluation of market conditions and prices upon which he could base such an adjustment to the Company's projections. His proposed adjustment to off-system sales is therefore speculative and is not adopted.

Mr. Dittmer also recommends an adjustment to increase the revenues to MPCo associated with capacity equalization payments under the Intercompany Interchange Contract ("IIC"). Again, Mr. Dittmer admits that his recommendation is based upon assumptions (without any factual basis about the IIC capacity reserve sharing calculations.) In the Company's rebuttal testimony, Ms. Turnage demonstrated that Mr. Dittmer's calculations werc flawed, that he overstated available capacity and that he gave no weight to the seasonal differences in the value of capacity as provided in the IIC and as shown in response to data requests on this issue. This adjustment is not adopted.

4. **Capital Structure and Cost of Capital.**

This Commission has reviewed the portions of the Stipulation agreeing to the Company's proposed capital structure and the weighted cost of the Debt, Trust Preferred Stock and Preferred Stock. This Commission adopts this portion of the Stipulation and finds that all of the elements of MPCo's proposed cost of capital, except for the Company's proposed rate of return on common stock equity, which will be considered separately, are just and reasonable and should be approved. The only other testimony was the recommendation of Dr. John Leglcr, thc expert witness for the Navy, who testified that an average of the 2000 and 2002 year end equity/debt ratio should be utilized for the test period rather than a year-end equity/debt ratio. While we agree that there may be some merit for using an average capital structure, the average should be developed using the beginning and ending of the projected test period – December 2001 and

December 2002 – and not year end 2000 and 2002. It should also be remembered that year 2000 is prior to the time of the equity infusion for the new units. This Commission is not persuaded by Dr. Legler and finds that the stipulated year-end equity/debt ratio, which is a requirement of PEP-2 previously approved by this Commission, is appropriate for use in this case. Since this filing and its results are to be considered in light of PEP-2 and will become a part of PEP-2, it is important that, where appropriate, the findings of this order should be consistent with PEP-2.

B. <u>RETURN ON COMMON STOCK EQUITY.</u>

This Commission heard a great deal of testimony regarding the Company's return on common stock equity, since a part of the Company's request for rate relief is related to an increase in its cost of capital – specifically, the cost of common stock equity. The Company asserts that the existing formulas for return on equity in PEP do not reflect current conditions in the financial markets and therefore do not produce an adequate return to investors. Three persons offered testimony regarding return on common equity – Mr. Charles Benore, Dr. John Legler, and Dr. Chris Garbacz. It is important to note that each of the three cost of capital witnesses testified to and supported a recommended rate of return, a range of returns which they considered reasonable and certain formulas or models used to develop those values. In each case, the formulas or models used differ from the current formulas in the PEP plan. We have carefully considered all of the information presented, and have spent considerable time and effort evaluating that information. This information should be considered to determine a return on the common stock equity for MPCo that is just and reasonable and consistent with companies of comparable risk; that complies with the Mississippi Public Utility Act and the Rules and Regulations of this Commission; and that complies with the requirements of the United States Supreme Court rulings in *Bluefield Water Works & Development Co. v. Public Service*

Commission of West Virginia, 262 U.S. 679 (1923) and *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944).

1. **Benore Testimony.**

Mr. Charles Benore testified for MPCo and recommended a 13.25% return on common equity. Mr. Benore used four models in arriving at a proposed rate of return on common equity for MPCo. Those four models are the Discounted Cash Flow Model ("DCF"), the Equity Risk Premium Model ("ERP"), an average of the standard Capital Asset Pricing Model ("CAPM") and the Empirical Capital Asset Pricing Model ("ECAPM"), and the "Comparable Earnings" Method. Mr. Benore's testimony provides descriptions of the DCF, ERP and CAPM models, as does the testimony of the other witnesses. The results of the first three market models were transformed by Mr. Benore in a process described below. Mr. Benore's fourth model, a "Comparable Earnings" Method, is also discussed below. For his DCF and CAPM models and his "Comparable Earnings" method, Mr. Benore selected comparable companies using nine (9) criteria or tests intended to assure that the companies used in these formulas were comparable to MPCo as to important matters such as risk. Mr. Benore testified that MPCo should be allowed a rate of return on common equity of 13.25%, including Transformation and Comparable Earnings, both of which are discussed below.

Mr. Benore's testimony included a calculation of return on common equity which used the same formulas considered by Dr. Garbacz - the DCF, ERP and CAPM (both standard and empirical averaged). Using these formulas in a manner similar to that used by Dr. Garbacz (without Transformation or the "Comparable Earnings" method), Mr. Benore's formulas on average resulted in a return on common equity of 11.47%.

Mr. Benore also used a fourth model, the "Comparable Earnings" method, which calculates a return on common stock equity for MPCo based on the earnings of comparable companies. This model is likewise described in Mr. Benore's testimony. This comparable earnings test or method was criticized by Dr. Garbacz, who testified that the companies were not truly comparable in his opinion, and further because it compared the retail earnings of MPCo with the total earnings of the other companies, which included wholesale and unregulated earnings. This test determined a return on equity for MPCo of 13.3%.

Mr. Benore further testified that the results of the DCF, ERP and the average of the CAPM models should be adjusted by a process called transformation. Transformation, according to Mr. Benore's direct testimony, "is the process that determines the necessary regulatory book return so that investors have an opportunity to earn their required market return." According to Mr. Benore, the standard models for regulatory book return do not provide the return required by investors when the ratio of market value to book value of common stock is above one (1). This Commission desires that companies under its regulatory control remain healthy and earn a return that allows them to attract the capital needed to provide the quality of service that we and their customers require of them. The argument presented was that transformation has not been accepted in any other regulatory rate proceeding. Since we cannot determine any other commission that has endorsed transformation, we are not able to accept this theory at this time.

2. **Legler Testimony.**

The second rate of return witness heard by this Commission was Dr. John Legler, on behalf of the Navy. Dr. Legler testified that he found a range between 10.5% and 11.5%, which would produce a just and reasonable return on equity for MPCo. His recommended return was

11.0%. In his rebuttal testimony, Mr. Benore noted several errors in Dr. Legler's calculations: an improper retention growth rate estimate for FPL Group, failure to add 0.5% to the growth rate for each of his comparable companies, and the use of August 31, 2001 prices instead of September 28, 2001 prices. Dr. Legler agreed on cross-examination that he had made errors in his direct testimony and when those errors are corrected and considered, Dr. Legler's Late Filed Exhibit____(JBL-1) Schedule 2 (Revised) indicates that his calculated return on equity would become 11.25% using an average of the models used. In response to questions on cross-examination, Dr. Legler gave an opinion that a range from 10.3% to 12.17% would result in a reasonable return. Dr. Legler used three (3) models to calculate his recommended return - DCF, ERP, and CAPM.

3. Garbacz Testimony.

The third rate of return witness testifying before this Commission was Dr. Chris Garbacz, on behalf of the Staff. In his pre-filed direct testimony, Dr. Garbacz determined a recommended rate of return of 11.45% for MPCo's return on common stock equity, using three (3) models -- DCF, ERP and CAPM (both standard and empirical averaged). The models applied by Dr. Garbacz and Mr. Benore were virtually identical. In rebuttal testimony, MPCo's expert witness, Mr. Benore, pointed out three errors in Dr. Garbacz's analysis. These errors were that Dr. Garbacz (1) failed to adjust the dividend to be received by investors to the first holding year as required by the DCF model, (2) failed to adjust the ERP and CAPM for flotation costs and only adjusted the DCF model, and (3) did not use the same time period for interest rates for the Equity Risk Premium and CAPM models as used for stock prices. Dr. Garbacz accepted the first two (2) of the three (3) corrections, which results in increasing his recommended return from 11.45%

to 11.67%. Dr. Garbacz then reduced his recommended return to 11.44% to reflect his claim that MPCo is less risky.

4. **Summary of Rate of Return Witnesses.**

Mr. Benore's range of reasonable returns for MPCo (without transformation or comparable earnings tests) is between 11.4% and 11.5%; Dr. Legler's range, as testified on cross-examination, is between 10.30% and 12.17%; and Dr. Garbacz's range, as corrected is between 11.22% to 11.67%, adjusted under PEP. As Dr. Legler stated on cross-examination, any rate of return selected by this Commission within these ranges would be reasonable. However, it also is obvious from studying these ranges of reasonable returns that the preponderance of the testimony would require a return in the 11.4% to 11.7% range, and that a rate of return in that range would result in just and reasonable rates for MPCo and its customers.

5. **Finding of Rate of Return.**

After considering and carefully analyzing all of the rate of return testimony and considering our experience with rate making, including both conventional and formula-type rate of return plans previously approved by this Commission, we find that a just and reasonable rate of return on common stock equity to be used as part of determining just and reasonable rates for MPCo's customers should be set at 11.5%. This rate of return is based upon the models and the substantial weight of the credible evidence and provides reasonable rates for the customers of MPCo and a fair return for the Company. We find that this rate would be equitable, just and reasonable for use in both a conventional rate case and for use in conjunction with a performance review and analysis under PEP-2.

C. PEP-2 CONSIDERATIONS.

Rate schedule PEP-2 and its predecessors have been the rate approved for setting the revenues of the Company since 1986. At the time PEP was first adopted, this Commission recognized the need to alter the conventional method of rate making to consider and adjust for the Company's performance in meeting the most important needs of its customers. The conventional rate setting process did not take into consideration the Company's performance or set rates based upon that performance. To provide for more emphasis on the needs of utility customers in Mississippi, this Commission in 1985 ordered the Company to develop and file a performance-based rate mechanism. After extensive review and deliberation, the PEP plan was adopted. This plan has allowed the Company the flexibility to balance competing priorities, to access capital necessary to construct and maintain facilities, to provide services needed by customers and, most importantly, to do all of these at rates which have been and are low in comparison to other utilities. Since then, this Commission has ordered most of the larger utilities under its regulatory authority to adopt similar performance-based ratemaking plans.

The history and lawfulness of the Company's performance evaluation plan is well settled under Mississippi law. This Commission agrees with the Staff and Company that PEP-2 constitutes a "formula type rate of return evaluation rate" under the provisions of Miss. Code Ann. 77-3-2 (2000). That section provides this Commission the authority for the adoption of and administration of formula type rate plans and authorizes the periodic calculation, review, and adjustment of revenues, performance, and rates of return.

The Company's retail rate mechanism PEP-2 was in effect at the time of the Company's filing of its notice of intent in this docket. Rate PEP-2 provides the basis for determining the just and reasonable revenue needs of MPCo and for fixing its rates. PEP-2 also includes a section entitled "Major Plant Addition or Modifications," which provides for changes in rates under PEP-2 when major new plant is added. MPCo's filing herein is pursuant to and authorized by this section of PEP-2.

The Staff and Company also jointly acknowledge, and this Commission concurs, that the construction of the Company's new combined cycle units at Victor J. Daniel Electric Generating Plant Units 3 and 4 constitute a major plant addition as contemplated by PEP-2, and that the Company's filing is authorized under PEP-2.

At the time that the Company filed this rate request under the "Major Plant Additions or Modifications" section of PEP-2, this Commission suspended the regular semiannual evaluations. The Staff and Company have stipulated, and this Commission concurs, that the Company should return to regular periodic PEP-2 evaluations at the end of 2002.

One object of the PEP plan is to promote rate stability. A key provision of PEP-2 limits rate changes resulting from regular semiannual evaluations to 2% of aggregate retail revenue. In order to return to normal operation of PEP and maintain rate stability, it is essential that, in deciding the rate request before us in this docket, the Commission also consider the ongoing operation of PEP-2 and make provision for appropriate integration of this decision with the ongoing operation of the PEP-2 plan.

In recognition of this, on October 30, 2001, this Commission ordered that all parties present such testimony as it deemed appropriate concerning the incorporation of the holding in this docket with and into PEP-2. This was done to recognize and allow for the orderly transition of this case to the normal and continued operations of PEP-2. In order to accomplish the integration of this proceeding with PEP-2 it is necessary for us to:

a. Include into PEP-2 the approved changes in this docket that are necessary to update and improve PEP-2 and to assure that PEP-2 continues to yield just and reasonable rates, and

b. Provide the means and requirements necessary to integrate the results of this case with the remaining provisions of PEP-2, which continues to be rate making mechanism for determining the Company's rates.

1. **Changes Necessary in PEP-2**

The Staff and the Company have stipulated to the following matters regarding PEP-2:

a. Future rate adjustments under PEP-2 should be determined based upon the middle of the Range of No Change, not on the top or bottom of the Range; and the "sharing" of rate increases and decreases based on price performance should be eliminated. An additional penalty/reward mechanism should be added as per the Stipulation.

b. The cash working capital value used in PEP-2 should be $0 (zero).

c. The CWIP in PEP-2 should include all projects ending within a year of the end of the evaluation period, with any related AFUDC included in operating income.

d. The Company's rate base in PEP-2 should include the regulatory asset Over/Under Recovery of Ad Valorem Taxes.

e. The following language should be added to Rate Schedule, "PEP-2" MPSC Schedule No. 28, page 3 of 28, under the section Filing Procedures:

> In considering any evaluation filed pursuant to this Rate PEP-2, nothing in this Rate shall be construed to prevent the Staff from disputing the accuracy of any investment, revenue or expense; from disputing that any investment, revenue or expense is prudent in amount or purpose or otherwise in accord with the Mississippi law, the Rules and Regulations of the Commission or this Rate PEP-2; or from disputing whether any item investment, revenue or expense is improperly recorded to an account. The Staff may request and the Company shall provide clarification and additional data underlying the entries subjacent to the categories of (1) Investment, (2) Revenues, and (3) Expenses.

f. The Company's initial evaluation under PEP-2, as revised pursuant to this Stipulation in this docket, should be made in February 2003, in accordance with the rate schedule based upon the twelve months ended December 31, 2002.

The Commission finds that the changes to PEP-2 proposed by the Stipulation will produce rates which, when combined with the other findings of this order, will be just, reasonable and in the best interest of the Company's customers and the Company, and we hereby adopt those changes for incorporation in PEP-2.

The Stipulation does not include any agreements regarding the calculation for the cost of common stock equity in PEP-2 (and specifically as to the models included for the calculation of K_{AVG}% therein), which is currently provided in Appendix C of that rate schedule.

There was testimony by some of the parties as to (1) whether the rate of return on common stock equity for a conventional case should become the K_{AVG} in PEP-2 (known previously as the benchmark) and, therefore, should be adjusted – up or down – for MPCo's performance or (2) whether the conventional rate of return should be the allowed return under PEP-2 including performance. This Commission is familiar with PEP-2 and its predecessors. We have never questioned that the conventional return on equity should be the benchmark or starting point (K_{AVG}) with adjustments to be made for performance according to the PEP rate schedule. We agree with witness Dr. Roger Morin that this is what was intended in the initial PEP and all subsequent changes to PEP.

This commission finds, based on the testimony of all the rate of return witnesses, that the present models used in PEP-2 may not currently produce a return on common stock equity (or K_{AVG} as it is referred to in PEP-2) which is just and reasonable.

This Commission is of the opinion that changes to the current models used in PEP-2 should be considered in a separate docket, and that the parties in this proceeding and any new intervenors should be given further opportunity to comment and offer testimony as to changes in the formulas. In order to accomplish this review and to assure that the models provide just and reasonable returns to the Company and likewise just and reasonable rates for MPCo's customers when the semi-annual evaluation under PEP-2 are reinstituted, we are simultaneously with the issuance of this order, issuing a Show Cause Order to MPCo which will establish a new docket to determine the sufficiency of the models which will be used to calculate a just and reasonable return on equity or K_{AVG} for PEP-2.

All of the changes made to PEP-2 by this order, including those adopted from the Stipulation, are subject to change at any time that this Commission finds that they or any other provisions of PEP-2 become unreasonable or cease to result in just and reasonable rates. As we have done in the past, including in this docket, we are not hesitant to call for and make any and all changes which might be necessary.

2. <u>Integration of the Findings in this Case with PEP-2.</u>

As this Commission has previously stated, PEP-2 continues to be the rate mechanism under which MPCo's revenue requirements are determined and changes in rates are made. PEP-2 in the Section entitled "Major Plant Additions or Modifications" allows for a change in rates that might be greater than the 2% limitation included in PEP-2, but does not eliminate any of the features of PEP-2. Since no filing under this section of PEP-2 (or any predecessor PEP) has heretofore been made or needed, this Commission feels a need to set forth the requirements and the results of a filing under that section.

The "Major Plant" section of PEP-2 requires that a filing for extraordinary relief due to