OCC EXHIBIT NO. ______

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In The Matter Of The Application Of Ohio Power Company For Authority To Establish A Standard Service Offer Pursuant To R.C. 4928.143, Revised Code, In The Form Of An Electric Security Plan	)))))	Case No. 13-2385-EL-SSO
In The Matter Of The Application Of Ohio Power Company For Approval Of Certain Accounting Authority	)))	Case No. 13-2368-EL-AAM

DIRECT TESTIMONY OF MATTHEW I. KAHAL

On Behalf of the
The Office of the Ohio Consumers' Counsel
10 West Broad Street, Suite 1800
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MAY 6, 2014

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I. QUALIFICATIONS

Q1. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A1. My name is Matthew I. Kahal. I am employed as an independent consultant working in this case for the economic consulting firm Exeter Associates, Inc. ("Exeter"). Exeter has been retained by the Office of the Ohio Consumers' Counsel ("OCC") to address certain issues in this docket. Exeter's business address is 10480 Little Patuxent Parkway, Suite 300, Columbia, Maryland 21044.

Q2. PLEASE STATE YOUR EDUCATIONAL BACKGROUND.

A2. I hold B.A. and M.A. degrees in economics from the University of Maryland and have completed course work and examination requirements for the Ph.D. degree in economics. My areas of academic concentration included industrial organization, economic development, and econometrics.

Q3. WHAT IS YOUR PROFESSIONAL BACKGROUND?

A3. I have been employed in the area of energy, utility, and telecommunications consulting for the past 35 years, working on a wide range of topics. Most of my work during my consulting career has focused on electric utility integrated planning, power plant licensing, environmental compliance issues, mergers, and utility financial issues. I was a co-founder of Exeter, and from 1981 to 2001, I was employed at Exeter as a Senior Economist and Principal. During that time, I took the lead role at Exeter in performing cost of capital and financial studies. In recent years, the focus of much of my professional work has expanded to include electric utility markets, power supply procurement, and industry restructuring. Prior to entering consulting, I served on the Economics Department faculties at the University of Maryland (College Park) and Montgomery College, teaching courses on economic principles, development economics, and business.

A complete description of my professional background is provided in Appendix A.

Q4. HAVE YOU PREVIOUSLY TESTIFIED AS AN EXPERT WITNESS BEFORE UTILITY REGULATORY COMMISSIONS?

A4. Yes. I have testified before approximately two dozen state and federal utility commissions, federal courts, and the U.S. Congress in more than 400 separate regulatory cases. My testimony has addressed a variety of subjects including fair rate of return, resource planning, financial assessments, load forecasting, competitive restructuring, rate design, purchased power contracts, environmental compliance, merger economics, and other regulatory policy issues. These cases have involved electric, gas, water, and telephone utilities. A list of these cases is set forth in Appendix B, with my statement of qualifications.

Q5. WHAT PROFESSIONAL ACTIVITIES HAVE YOU ENGAGED IN SINCE LEAVING EXETER AS A PRINCIPAL IN 2001?

A5. Since 2001, I have worked on a variety of consulting assignments pertaining to electric restructuring, purchase power contracts, environmental controls, cost of capital, and other regulatory issues. Current and recent clients include the U.S. Department of Justice, U.S. Air Force, U.S. Department of Energy, the Federal Energy Regulatory Commission, Connecticut Attorney General, Pennsylvania Office of Consumer Advocate, New Jersey Division of Rate Counsel, Rhode Island Division of Public Utilities, Louisiana Public Service Commission, Arkansas Public Service Commission, the Maryland Public Service Commission, the Maine Public Advocate, the New Hampshire Consumer Advocate, the Maryland Department of Natural Resources, the Maryland Energy Administration, and certain private clients.

Q6. HAVE YOU PREVIOUSLY TESTIFIED ON THE SUBJECTS OF ELECTRIC RESTRUCTURING, TRANSITION TO COMPETITION, AND RETAIL DEFAULT SERVICE?

A6. Yes. I have testified on these topics on numerous occasions during the past ten to fifteen years. This includes the design of programs to provide generation supply service for those retail electric customers requiring default service. Please see Appendix C for a listing of such cases.

II. OVERVIEW AND SUMMARY

A. Purpose of Testimony

Q7. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A7. The principal purpose of my testimony in this case is to evaluate the Utility's assertion that the proposed ESP III passes the ESP versus MRO test. In addition to the ESP versus MRO test, my testimony also addresses AEP Ohio's proposed Purchase of Receivables ("POR") program and certain aspects of its proposed SSO power procurement process and the resulting SSO retail pricing.

On December 20, 2013, Ohio Power Company (referred to as "AEP Ohio" or "the Utility") submitted an application to the Public Utilities Commission of Ohio ("PUCO" or "Commission") for PUCO's approval of a new Electric Security Plan ("ESP"). This would be the Utility's third such plan, and it is therefore referred to as "ESP III." As discussed in the application and related filings made by AEP Ohio ("Application"), and summarized in my testimony, ESP III incorporates a plan for standard service offer generation, along with numerous "rate rider" cost recovery mechanisms pertaining to generation, transmission, and distribution. The proposed ESP III covers the time period June 1, 2015 through May 31, 2018, a period of 36 months. It should be noted that AEP Ohio also proposed an early termination provision that give it sole discretion to end the proposed ESP III after two years.

As explained in the Application, Ohio statute requires that electric distribution utilities ("EDUs") provide a standard service offer ("SSO") for customers that do not take competitive generation service from entities other than EDUs, either through an ESP or a market rate offer ("MRO"). As it has done in the past, AEP Ohio proposes for this case to meet its SSO obligation through the use of an ESP. Approval of an ESP by the PUCO requires that the Utility demonstrate that its proposed ESP is more favorable, in the aggregate for its customers, than the MRO alternative. This has been referred to as the "ESP versus MRO test," and how the test is implemented has been a subject of much dispute in previous ESP cases. The full wording of the test is stated in R.C. 4928.143(C)(1) and is what I am referencing when I use shorter forms to state the test.

AEP Ohio witness Allen presents testimony asserting that the proposed ESP III is more favorable, in the aggregate, for customers than an MRO, for both quantified customer cost savings and qualitative public policy reasons. The principal purpose of my testimony in this case is to evaluate the Utility's assertion that the proposed ESP III passes the ESP versus MRO test. Since this test is a comprehensive analysis of the proposed ESP in the aggregate, I incorporate the findings and recommendations from other OCC witnesses that have a bearing on the merits of the proposed ESP III.

In addition to the ESP versus MRO test, my testimony also addresses AEP Ohio's proposed Purchase of Receivables ("POR") program and certain aspects of its proposed SSO power procurement process and the resulting SSO retail pricing.

Q8. WHAT ISSUES IN AEP OHIO'S APPLICATION ARE ADDRESSED BY OTHER OCC WITNESSES?

A8. OCC witness Mr. Jonathan Wallach addresses class cost allocation associated with certain proposed distribution-related riders. OCC witness Dr. Randall Woolridge responds to Utility witness Dr. Avera on AEP Ohio's cost of capital. OCC witness Mr. James Wilson evaluates the Utility's proposal to include in customers' retail rates the potential costs and savings of its retained purchase power contract with the Ohio Valley Electric Corporation ("OVEC"). OCC witness Mr. David Effron addresses the design and merits of certain distribution service-related rate riders proposed in this case. OCC witness Mr. Jim Williams testifies to how the rate increases in the application will affect affordability of service to customers. Mr. Williams also presents OCC's general position on purchase of receivables. As discussed in my testimony, in evaluating the ESP versus MRO test, I incorporate the findings and recommendations of OCC witnesses Wilson and Effron. However, I conclude it is not necessary at this time to include the recommendations of OCC witness Wallach or OCC witness Woolridge directly as part of the ESP versus MRO test. The recommendations of those two OCC witnesses stand on their own even if the Commission approves an ESP in this case as being superior to the MRO.

Q9. HOW DID THE UTILITY CONCLUDE THAT ITS PROPOSED ESP WOULD BE SUPERIOR TO AN MRO?

A9. This ESP versus MRO test is addressed only very briefly in the testimony of witness Allen. His position is that the Utility's proposed auction process would produce essentially the same SSO generation supply price (over the three-year ESP) as an MRO. However, the Utility proposes to include in its ESP a continuation of the $14.688 million per year residential distribution credit established in its last rate case and due to expire in May 2015. Thus, over three years, Mr. Allen claims that the proposed ESP III provides a quantified savings, relative to the MRO, of approximately $44 million.[1] In addition, he asserts that other features of the proposed ESP III proposal provide non-quantifiable benefits to customers. He asserts that these qualitative benefits cannot be quantified.[2]

Q10. DID THE PUCO APPROVE AND MODIFY AEP OHIO'S CURRENT ESP?

A10. Yes. The PUCO's August 3, 2012 Opinion and Order approved AEP Ohio's previous ESP Proposal (i.e., "ESP II") in Case Nos. 11-346-EL-SSO et al., which is the ESP currently in place, and ruled that it passed the ESP versus MRO test, but only after making significant modifications. In approving the modified ESP II, the Commission noted that a vitally important qualitative benefit is that the Utility's plan, as modified by the PUCO, would facilitate a faster transition to a

[1] Allen testimony, at 4.

[2] *Id.*, at 5.

fully competitive SSO.[3] However, with AEP Ohio's recent transfer of its generation assets (except for OVEC), that transition has now been completed. Therefore, it is now feasible and essentially necessary for AEP Ohio to fully supply generation for SSO service from the competitive wholesale market, as Mr. Allen seems to acknowledge and as has been proposed in this Application. Hence, the context for evaluating the proposed ESP III is completely different from the context of the PUCO's review of ESP II.

At the time of the ESP II case, AEP Ohio continued to own and operate its legacy generation assets, which could be used to provide SSO default generation service. At issue in that case was what pricing would be appropriate for the SSO given both prevailing market conditions and AEP Ohio generation asset ownership. Also at issue in that proceeding was how the Utility's proposed pricing (and the PUCO's modification of that proposal) compared with an MRO alternative. By comparison, in this case, AEP Ohio owns no generation resources (other than the OVEC contract), and the Utility proposes that all SSO supply will be acquired at wholesale market prices through a series of competitive auctions.

[3] *In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to Section 4928.143 Revised Code, in the form of an Electric Security Plan, Opinion and Order*, Case Nos. 11-346-EL-SSO and 11-348-EL-SSO, August 8, 2012, at 76.

Q11. WHAT DO YOU CONCLUDE REGARDING THE ESP VERSUS MRO TEST IN THIS CASE?

A11. My testimony demonstrates that AEP Ohio's proposed ESP III is less favorable in the aggregate than an MRO, and therefore ESP III, as filed, should ***not*** be approved.

I agree with Mr. Allen that the proposed competitive procurement process for SSO supply in the proposed ESP is effectively the same as the procurement process under an MRO. Hence, the question is whether, in the aggregate, customers benefit from the various proposed riders in ESP III, inclusive of the proposed OVEC purchase power rider, the proposed Sustained and Skilled Workforce Rider ("SSWR"), other proposed riders or programs, and the $14.688 million per year residential distribution credit. They do not.

It appears that, in the aggregate, the ESP III proposal, even with the residential distribution credit, will produce higher customer rates than a stand-alone MRO. While AEP Ohio's witnesses assert there are qualitative benefits from the programs or resources funded by the various new (or amended) riders, they have failed to demonstrate why the same or similar benefits could not be obtained from pursuing the collection of those costs in standard (traditional) base rate cases. That is, whatever qualitative benefits are claimed for these riders could instead be more properly addressed as part of a standard base rate case, where AEP Ohio's overall cost of service, rates, and utility earnings can be comprehensively evaluated by the PUCO in a base rate proceeding.

Moreover, the outcome of the test should be determined using quantitative factors. The use of qualitative factors to reduce or cancel out a more objective quantitative analysis is problematic.

Q12. WHAT IS YOUR RECOMMENDATION CONCERNING AEP OHIO'S PURCHASE OF RECEIVABLES PROPOSAL?

A12. The ESP III filing, through AEP Ohio witness Gabbard's testimony, proposes the introduction of a POR in conjunction with a comprehensive Bad Debt Rider. A key feature of this program is that AEP Ohio would purchase the receivables (with some limited exceptions) from the participating competitive retail electric service ("CRES") suppliers at 100 cents on the dollar, i.e., no discount for potential non-collection of receivables of the CRES providers. Instead, this cost of non-collection would be passed on to all customers (along with the SSO bad debt expense) in the proposed Bad Debt Rider. The Utility believes such a program will greatly enhance CRES supplier participation in the AEP Ohio retail market, particularly for small customers.

It is not the purpose of my testimony to address whether a POR program is appropriate in general because that is being addressed by OCC Witness Williams. If the PUCO adopts a POR despite OCC's general recommendation against it, however, I do recommend that the PUCO reject AEP Ohio's proposed zero discount design feature of the POR program. Instead, a reasonable discount value should be built in so that utility payments to the participating CRES entities reflect a realistic estimate by AEP Ohio of CRES suppliers' bad debt expenses. My testimony explains why I believe this modification to the Utility's proposal is essential to protect customers from bearing the burden of paying an improper subsidy to unregulated suppliers. With this change in the POR program, the Utility's proposal to charge customers for a bad debt expense rider would not be needed.

Q13. HOW DOES AEP OHIO INTEND TO ACQUIRE GENERATION SUPPLY FOR STANDARD SERVICE OFFER CUSTOMERS DURING THE TERM OF THE ESP?

A13. As described in detail by AEP Ohio witness Dr. LaCasse, the Utility intends to have an independent third party conduct a series of descending clock auctions ("auctions") to procure wholesale full requirements contracts ("FRCs") to serve the entire SSO loads for this three-year ESP. The auctions would be conducted twice per year beginning September 2014, or a total of six auctions. The auctions would procure power through a mix of one-year and two-year contracts. The Utility proposes that about two-thirds of supply for SSO load would be from one-year contracts, and the remaining one-third of the generation supply under two-year contracts. The FRCs would include all required generation products, including energy, capacity, ancillary services, and certain market-related transmission products required by PJM. AEP Ohio would provide the "nonmarket" transmission to all customers (SSO and shopping alike), principally the Network Integration Transmission Service ("NITS") component.

Please note that the amount of "bundled generation" supplied under these proposed FRCs will depend entirely on the magnitude of the SSO load, which can change significantly over time. There are no fixed charges (i.e., charges that do not vary with load served) in the FRCs, nor are there minimum or maximum generation supply amounts. This means that wholesale suppliers who are successful bidders in the auctions must absorb the risks associated with unpredictable changes in SSO load. This risk can be important when there are abrupt changes in customer participation in the SSO, and it inevitably will be priced into the auction supply bids.

Q14. HOW DOES AEP OHIO PROPOSE TO RECOVER ITS STANDARD SERVICE OFFER COSTS UNDER ITS ELECTRIC SECURITY PLAN?

A14. AEP Ohio proposes to use rate riders to recover the costs of the FRCs, any incremental costs associated with conducting the auctions, and (nonmarket) transmission costs (mainly NITS) on a dollar-for-dollar basis. The generation rates would be set annually based on the auction clearing prices, with a reconciliation rider for any under/over cost recovery. The SSO generation rates will be set by major customer classes, taking into account differences in class voltage and coincident peak demand load factors. The Utility's filing indicates that the residential class accounts for the vast majority of the SSO load (about two-thirds according to AEP Ohio). AEP Ohio contends that the residential class has a higher line loss factor and a weaker (i.e., lower) coincident peak load factor than the nonresidential classes (as a whole). AEP Ohio's pricing methodology therefore assigns the residential class higher $-per-MWh prices than the nonresidential classes for SSO service. Based on the data in the Utility's filing, I estimate this premium for residential versus nonresidential in year one to be roughly 15 percent.

Q15. DO YOU CONSIDER AEP OHIO'S PROPOSED STANDARD SERVICE OFFER TO BE ESSENTIALLY A MARKET RATE OFFER?

A15. Yes, as a general matter, I recognize this plan as being market-based, reflecting the prevailing conditions in the PJM region competitive wholesale market. However, AEP Ohio's translation of the FRC-blended prices into customer class-specific SSO prices is partly market-based and is partly derived from a nonmarket administrative formula.

Q16. WHAT ARE YOUR RECOMMENDATIONS WITH RESPECT TO THE UTILITY'S STANDARD SERVICE OFFER SUPPLY PLAN?

A16. In general, I find the SSO supply plan to be reasonable and technically sound. However, I recommend two changes. AEP Ohio proposes to procure a mix of one- and two-year FRCs, stating that such a portfolio is attractive to suppliers as compared to only procuring one-year contracts. However, the Utility limits the procurement of two-year contracts to the first year, with 100 percent of generation supply in year three coming from one-year contracts, after the initial two-year contracts expire. I recommend instead that additional two-year FRCs be procured in year two so that the SSO supply in year three will be based on a portfolio mix of one- and two-year contracts. This modification would reduce potential price volatility as compared to the Utility's proposed contract structure.

My second recommendation pertains to the Utility assigning the residential class an SSO price premium based on a weaker coincident peak demand load factor. (Note that I do not contest the higher residential price due to a higher loss factor.) Based on my experience, the residential class SSO load tends to be more stable over time (i.e., more gradual migration to competitive service) than the nonresidential classes. This residential load stability or low "migration risk" has considerable value to wholesale suppliers under the FRC contract structure, and this risk attribute is undoubtedly priced into the auction bids. Since AEP Ohio's proposed auction acquires a single uniform product for all customer classes collectively, this means that all customer classes will enjoy the price-reducing benefit provided by the residential customer class's large size and stability. A reasonable way of accounting for this beneficial spillover of cost savings provided by residential SSO customers would be to not charge residential customers a price premium due to the lower class load factor. In my opinion, the Utility's customer class pricing method does not fully reflect market requirements and it overcharges residential customers for the SSO. Alternatively, separate FCAs could be acquired in the auctions for the residential and the non-residential classes, and the charges for each customer class could be established according to those separate market-clearing price results.

B. Organization of Testimony

Q17. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A17. Section III provides a general description of the proposed ESP III and my evaluation of the ESP versus MRO test. Section IV discusses the proposed POR program (and associated Bad Debt Rider) and how I believe that program should be modified. Section V addresses the planned SSO competitive procurement and retail pricing and my recommended modifications.

III. THE ESP VS. MRO TEST

A. The Statutory Test

Q18. WHAT IS YOUR UNDERSTANDING OF THE STATUTORY REQUIREMENT FOR PUCO APPROVAL OF AN ESP?

A18. As acknowledged by the Utility in its Application, electric distribution utilities may satisfy the requirement to provide a standard service offer either through an ESP or an MRO. (Ohio Revised Code, Section 4928.141(A).) The requirements for an MRO include a competitive bid process ("CBP") that adheres to certain standards, procedures, and criteria specified in Ohio Revised Code, Section

4928.142. The requirements and potential features of an ESP are specified in Ohio Revised Code, Section 4928.143. That section addresses the establishment of SSO generation rates and a number of other aspects of electric service, including "distribution infrastructure and modernization," which are not part of the MRO provision of the Code.

The ESP section of the statute also specifies the test that an electric distribution utility must pass to obtain PUCO approval of an ESP. If the utility proposes an ESP, the PUCO

> "...shall approve or modify and approve an application filed under division (A) of this section if it finds that the electric security plan so approved, including its pricing and all other terms and conditions, including any deferrals and any future recovery of deferrals, is more favorable in the aggregate as compared to the expected results that would otherwise apply under section 4928.142 of the Revised Code." (Ohio Revised Code 4928.143(C)(1))

The statute further states that the utility has the burden of proof under this provision. (*Id.*)

Q19. HOW DID THE PUCO APPLY THE STATUTORY TEST IN AEP OHIO'S PREVIOUS ESP CASE?

A19. In the Utility's ESP II case, the PUCO conducted the statutory ESP versus MRO test after making several modifications to the AEP Ohio filed case.[4] The PUCO first considered the ESP generation price, as modified in its order, then other quantifiable and non-quantifiable attributes of all proposed ESP terms and conditions. The PUCO determined that the proposed ESP price, as modified, would provide a net customer benefit of $9.8 million.[5] The PUCO then identified other quantifiable costs of the ESP to be $386 million, such that it believed the MRO to be more favorable by $386 million.[6] Finally, the PUCO concluded that the qualitative benefits of the modified ESP significantly outweighed the cost of the ESP, with the "most significant of the non-quantifiable benefits" for the ESP being the accelerated transition (by June 1, 2015) to a full market-based pricing for the SSO generation supply.[7]

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[4] *In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to Section 4928.143 Revised Code, in the form of an Electric Security Plan, Opinion and Order*, Case Nos. 11-346-EL-SSO and 11-348-EL-SSO, August 8, 2012, at 70-77.

[5] *Id.*, at 75.

[6] *Id.*

[7] *Id.*, at 76.

Q20. IS THE PUCO'S DECISION IN AEP OHIO'S LAST ESP CASE APPLICABLE TO THE CURRENT CASE?

A20. While the statutory criteria and standards used in the last case for the ESP versus MRO test obviously have not changed, AEP Ohio's circumstances have changed. As discussed below, the SSO generation price is not at issue in the ESP III case because the Utility concedes it would be essentially identical under both the proposed ESP and an MRO. The PUCO placed considerable weight in its decision in the last case on its finding that the approved ESP (with PUCO modifications) fostered a prompt transition to a full market price as being the most significant benefit. That qualitative benefit that was important to the PUCO is moot in this case, as there will be a full market-determined price for SSO generation under either the ESP or MRO options.

Given the important changes in circumstances and context since the last case, a completely new ESP versus MRO test is required.

B. AEP Ohio's Position

Q21. HOW HAS AEP OHIO ATTEMPTED TO SHOW THAT ITS PROPOSED ELECTRIC SECURITY PLAN IN THIS CASE PASSES THE STATUTORY TEST OF BEING MORE FAVORABLE IN THE AGGREGATE THAN THE MARKET RATE OFFER ALTERNATIVE?

A21. AEP Ohio witness Allen presents testimony alleging that the proposed ESP III is more favorable in the aggregate than what would be expected under an MRO, which he refers to as being "narrowly focused." His testimony acknowledges that "there is no quantifiable difference in the commodity prices that would be assumed under an ESP or MRO."[8] This finding is further confirmed in Utility responses to OCC-INT-3-23 and OCC-INT-3-24. The responses indicate that AEP Ohio would use the same generation supply procurement process under both an ESP and an MRO.

Q22. DOES WITNESS ALLEN QUANTIFY AN OVERALL CUSTOMER BENEFIT FROM THE PROPOSED ELECTRIC SECURITY PLAN?

A22. Yes, although the only quantified benefit (as compared to the MRO) asserted by witness Allen is the Utility's voluntary offer to continue, until May 31, 2018, the current Residential Distribution Credit Rider, which is due to expire on May 31, 2015. This rate credit has an annualized value of $14.688 million, or about $44

[8] Allen, direct testimony, at 4.

million for the full three-year term of the proposed ESP, or about $29 million if AEP Ohio exercises its asserted right to terminate the ESP after two years. He states that this rate credit would not be provided under an MRO, and therefore, it is a benefit only associated with the proposed ESP. The Utility acknowledges that this $44 million (or possibly $29 million) rate credit is the only benefit that it has quantified under its proposal. (Response to OCC-INT-3-25.)

Q23. HAS MR. ALLEN PRESENTED A DISCUSSION OF THE ASSERTED QUALITATIVE BENEFITS ASSOCIATED WITH THE PROPOSED ELECTRIC SECURITY PLAN III?

A23. Yes, his testimony briefly reviews some of the key elements of the Utility's proposal, other than the CBP sponsored by Dr. LaCasse, and identifies what he alleges are the salient qualitative benefits as compared to the MRO.

1. <u>The Distribution Investment Rider ("DIR") and Enhanced Service Reliability Rider ("ESRR")</u>. He argues that these riders will allow the Utility to invest in distribution infrastructure and will improve reliability while avoiding the "higher costs" and "complexities" of rate cases. He strongly implies that approving these (and other) riders will allow the Utility to "maintain distribution rates constant" until May 31, 2018.[9]

[9] *Id.*, at 4.

2. Purchase of Receivables Program. The proposal for a POR program is sponsored by Utility witness Gabbard. Witness Allen alleges that this voluntary program will benefit customers by enhancing retail supplier market activity and providing customer convenience benefits. I address this program proposal in detail in Section IV of my testimony.

3. The OVEC PPA Rider. While AEP Ohio is not at this time asserting any quantified customer savings from the OVEC contract, it argues that including this PPA in rates will enhance customer rate stability. The PPA Rider and the attributes of the OVEC contract are evaluated by OCC witness Wilson.

The Utility in this case has proposed a number of other new riders or modifications to existing riders, but Mr. Allen is not claiming any qualitative benefits under the ESP versus MRO test. (Response to OCC-INT-12-285.) For example, the Utility is proposing the Sustained and Skilled Workforce Rider ("SSWR"), but this is not included in Mr. Allen's discussion of the test.

Q24. IS AVOIDANCE OF A BASE RATE CASE DURING THE TERM OF THE ELECTRIC SECURITY PLAN AN IMPORTANT BENEFIT?

A24. No, not necessarily, as I will explain below and as is discussed in OCC witness Effron's testimony. At the outset, although it may appear that witness Allen is suggesting a rate case stay-out if ESP III, with its proposed riders, is approved, the Utility is making no such commitment. AEP Ohio witness Vegas only goes so far as to state that, absent approval of the DIR, a base rate case "would be needed."[10] The response to OCC-INT-9-142 is rather vague about prospects for a base rate case between now and 2018. While the response suggests that, absent the DIR, a rate case is likely, the response also admits that such a filing may take place even with the DIR approval. The response also states that the need for rate cases, absent approval of the proposed riders, has not yet been evaluated.

Q25. HAS THE UTILITY EVALUATED THE RATE IMPACTS OF ITS PROPOSED RIDERS?

A25. Yes. This is presented in the testimony of AEP Ohio witness Roush. His Exhibit DMR-1 shows the rate impacts of all existing and proposed riders for each year of the three-year ESP. His exhibit compares those prospective impacts during ESP III to the current or near-term rate level of each rider. In each case, his rate impacts are shown in $-per-MWh. Please note that his exhibit shows that there will be no change over the ESP III period for many of these riders, as compared to current rate levels (with known changes) except for the DIR, SSWR, ESRR, and Auction Cost Reconciliation Rider ("ACRR"). (The ACRR, which includes the incremental costs of running the auctions, should be omitted from this discussion because it would be identical under both the ESP and MRO.)

[10] Vegas, direct testimony, at 7-8.

Q26. FOR THE RIDERS PROPOSED UNDER ELECTRIC SECURITY PLAN III THAT ARE UNRELATED TO GENERATION SUPPLY FOR THE STANDARD SERVICE OFFER, WHAT ARE MR. ROUSH'S RATE IMPACTS?

A26. The table below shows the current or near-term rate impact, the projected June 1, 2015 to May 31, 2018 rate impact (based on a three-year average), and the net change for the DIR, SSWR, and ESRR, expressed in dollars-per-MWh as estimated by AEP Ohio.[11]

Rider	**Current Rate**	**3-Year Average Projected Rate**	**Net Change**
DIR[12]	$3.06/MWh	$4.89/MWh	+ $1.83/MWh
SSWR	0.00	0.14	+ 0.14
ESRR	0.79	0.75	(0.04)
Total			**+ $1.93**

Source: Derived from Roush Exhibit DMR-1.

The ESP III (non-generation supply) riders will result in a net rate increase of $1.93 per MWh compared to current rates. Since Utility witness Kyle's Exhibit MDK-1 projects AEP Ohio's retail sales to be about 41.3 million MWh per year during ESP III, the $1.93 per MWh rate increase would produce a cumulative

[11] See Roush Exhibit DMR-1.

[12] For consistency with the Utility's proposal, the DIR is adjusted to include Phase I of gridSMART.

three-year revenue increase from these riders of about $240 million. AEP Ohio provides no demonstration that customer benefits from these riders will equal or exceed the $240 million cost increase during these three years, or that the collection of these additional revenues is warranted.

C. Evaluation of the ESP versus MRO Test

Q27. WHAT IS YOUR RESPONSE TO MR. ALLEN'S CONCLUSIONS ON THE ESP VERSUS MRO TEST?

A27. While I am not recommending that the PUCO consider qualitative factors for the test, after considering both the quantitative impacts on customers and the qualitative attributes of the Utility's proposal, I conclude that ESP III, as proposed by AEP Ohio, would be less favorable to retail customers in the aggregate than the alternative of an MRO. I base this on the following considerations:

- The CBP proposed by the Utility and described by Dr. LaCasse is a neutral factor since it would be essentially identical under both the ESP and MRO. I am in agreement with Mr. Allen on this point.
- The role of the $44 million (three-year) residential distribution credit is unclear in the ESP versus MRO test. It is highly questionable whether the $14.688 million per year rate credit is a quantifiable ESP III benefit, given the

simultaneous presence in ESP III of the extended and expanded DIR.

- The proposed extension and modification of the DIR, along with other proposed riders, will result in customers paying $240 million more for the three-year ESP, as noted above, before even considering the adverse rate impact of the OVEC contract.
- The Utility's plans for a rate case, even if its ESP III program is adopted as filed, is unclear. While AEP Ohio testimony suggests a rate case stay-out, there is no such actual commitment and thus not a benefit for customers.
- The proposed POR program will harm customers by forcing them to pay for (meaning subsidize) bad debt expense that is more properly the responsibility of CRES providers. This is an actual dollar harm to customers.
- While AEP witness Roush's analysis assumes no rate impact from charging customers for the OVEC contract, OCC witness Wilson demonstrates an expected three-year ratepayer cost of about $117 million. Even if the residential distribution rate credit is viewed as a pure benefit, this would be swamped by the cost penalty of the OVEC contract. Moreover, the rate stability benefit

claimed by the Utility for including the OVEC contract in rates is questionable.

- As explained by OCC witness Effron, the implementation of the SSWR and the proposed changes to the DIR (such as adding general plant) are inappropriate and potentially adverse to ratepayers. The SSWR and the DIR modifications are not addressed as qualitative benefits of the ESP III. Above all, Mr. Allen has not made a convincing argument concerning why it is appropriate to continue or increase DIR costs instead of seeking collection of costs in a base rate case.

Q28. WHAT IS THE SOURCE OF THE ANNUALIZED $14.688 MILLION RESIDENTIAL DISTRIBUTION RATE CREDIT?

A28. The rate credit rider resulted from a settlement in AEP Ohio's most recent distribution base rate case.[13] The Stipulation reached in that case provides a zero net rate increase (Paragraph IV.A.) by first increasing rates by $46.7 million and then offsetting that increase with a rate credit rider extending to May 31, 2015 (Paragraph IV.A.4). The Stipulation recognized that the DIR was being sought by AEP Ohio in the ESP II case with an initial year cap of $86 million. Thus, "to

[13] *In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company, Individually and if Their Proposed Merger is Approved as a Merged Company (collectively AEP Ohio) for an Increase in Distribution Rates*, Joint Stipulation and Recommendation, Case Nos. 11-351-EL-AIR and 11-352-EL-AIR.

prevent any potential excess collection of the DIR…," the Stipulation included a $62.344 million total revenue credit. (Id., paragraph (3).) This includes the annualized $14.688 million residential rate credit extending to May 31, 2015 referenced by witness Allen. The $62.344 million rate credit was calculated by subtracting $23.656 million related to post-date certain distribution investments identified in the rate case from the approved DIR cap of $86 million. The rate credit had the effect of fully offsetting the authorized $46.7 million distribution rate increase (i.e., the AEP Ohio revenue deficiency from the rate case) so as to provide a zero net base distribution rate increase. (Stipulation, paragraph 4.)

The rate case settlement was effectively able to coordinate the Utility's base rate case results with the revenues to be collected from customers through the DIR. That is, the establishment of the rate credit was a means of addressing potential Utility overcollection from customers of distribution revenues from a combination of the conventional rate case and the DIR mechanism.

Q29. HOW DOES THIS BACKGROUND ON THE RESIDENTIAL REVENUE CREDIT RELATE TO AEP OHIO'S PROPOSAL IN THIS CASE?

A29. Mr. Allen does not explain why the Utility is unilaterally and voluntarily proposing to extend the current residential distribution credit rider in this case. He refers to this as an unambiguous benefit of ESP III and implies that it is nothing more than a voluntary transfer of wealth from shareholders to customers.

The stipulation from the last base rate case makes it clear that the residential revenue credit rider is the direct result of introducing the DIR and seeking to avoid overcollection of distribution costs. In one sense, however, Mr. Allen is correct. If the PUCO were to approve ESP III exactly as proposed, then ratepayers would be better off receiving this credit than not receiving this credit. However, that is not the issue. In its proposed ESP III, the Utility not only seeks to continue the DIR (which is what created the need for the current residential rate credit), but it seeks to modify and expand it, with increased costs to customers, as documented by witness Roush's rate projections.

Q30. WHAT DOES ALL OF THIS SUGGEST?

A30. The $14.688 million per year rate credit is not a "windfall" or new benefit to customers, but rather this credit may be needed to correct excess revenue collections under the extended and expanded DIR. I say "may" because, unlike the circumstances in 2011, there is no base rate case investigation taking place that would determine whether the $14.688 million annual credit is sufficient to prevent excess revenue collection that might occur absent a rate case.

My conclusion is that it is highly questionable at least as to whether it is proper to view the continuation of the $14.688 million per year rate credit as a quantifiable ESP III benefit, given the concurrent proposal in ESP III for an extended and expanded DIR.

Q31. HAS THE UTILITY PRESENTED ANY ANALYSIS DEMONSTRATING EITHER BENEFITS OR COST EFFECTIVENESS FROM DISTRIBUTION INVESTMENT RIDER EXPENDITURES?

A31. No, AEP Ohio has not provided such a demonstration. Witness Dias, at page 16 of his testimony, presents a capital forecast for DIR-related investments averaging about $230 million per year. However, there is no documentation of benefits nor is there a demonstration that there will not be excess revenue collection.

Q32. IS THE USE OF CONVENTIONAL RATE CASES A VIABLE ALTERNATIVE TO THE DISTRIBUTION INVESTMENT RIDER FOR COLLECTION OF REVENUE FOR THE PLANNED INFRASTRUCTURE COSTS?

A32. Yes, as Mr. Allen recognizes in his testimony and in his data responses. AEP Ohio's argument against the use of base rate cases as the cost collection method is that rate cases are costly and complex. (See also his response to OCC INT-9-142(a).) However, Mr. Allen provides no estimate of the Utility's rate case expense, and such costs are likely to be modest compared to the hundreds of millions of dollars proposed to be collected in the DIR. Moreover, the Utility has not ruled out having a rate case at some future point during ESP III, even with the DIR. Mr. Allen's "complexity" and rate case litigation cost arguments are not persuasive.

Q33. HOW DO THESE ISSUES PERTAIN TO THE ESP VERSUS MRO TEST?

A33. Due to the absence of demonstrated benefits and the potential for excess cost collection from customers, the DIR in its proposed form should **not** be regarded as a qualitative benefit for ESP III. Nor is there any clear evidence that the $14.688 million residential revenue credit is an actual benefit when combined with the DIR proposal. The potential excess revenue collection problem can only be tested in a base rate case.

Q34. PLEASE SUMMARIZE YOUR ESP VERSUS MRO TEST FINDINGS.

A34. Both the Utility and I are in agreement that the SSO pricing would be the same under the ESP and MRO options. While Mr. Allen asserts quantified net benefits of $44 million from the residential revenue credit, I recommend that the PUCO find this alleged benefit to be questionable since it is tied to a DIR mechanism that can potentially collect excess revenues. What has been documented in this case is that the various new, expanded, or modified riders will increase delivery service revenues (meaning increase customer payments to AEP Ohio) by a three-year total of about $240 million. In addition, witness Wilson has demonstrated a net cost to customers from the proposal for the OVEC contract of about $117 million, with only a modest benefit at best in terms of greater rate stability. Finally, I do not agree that the proposed ESP provides qualitative benefits to customers. Ratepayers will be harmed by the POR program in its proposed form, and the SSWR is inappropriate, as explained by OCC witness Effron.

IV. THE PURCHASE OF RECEIVABLES PROGRAM PROPOSAL

Q35. WHAT IS AEP OHIO'S PROPOSAL CONCERNING THE DESIGN AND IMPLEMENTATION OF A PURCHASE OF RECEIVABLES ("POR") PROGRAM?

A35. This proposal is set forth in the Direct Testimony of Stacey D. Gabbard. Witness Gabbard notes that the Utility was ordered by the PUCO in the ESP II decision to evaluate a POR program, and he presents AEP Ohio's POR proposal "in concert with a bad debt rider" in his testimony.[14] The program would involve those Competitive Retail Electric Service ("CRES") suppliers that engage with AEP Ohio in consolidated billing, and it has the following major features:

- For CRES suppliers participating in the POR program, AEP Ohio will pay those suppliers for their receivables incurred after the program's inception. Such payments will cover the "commodity" or generation portion of the receivables and not other charges (such as termination fees).
- AEP Ohio proposes a zero discount on the payments to the CRES suppliers, which means that the CRES suppliers (going forward) will be insulated from bad debt expense. Rather, AEP Ohio will incur that expense and make its

[14] Gabbard direct testimony, at 3.

customers pay it dollar-for-dollar. However, witness Gabbard leaves open the possibility of a non-zero discount in the future.[15]

- AEP Ohio proposes to charge the participating CRES suppliers for the POR program's implementation and ongoing administrative costs.
- Witness Gabbard states that the timing of AEP Ohio's payments to CRES providers under this program is such that it will be "as neutral as possible" for working capital.[16] That is, it would have no effect—positive or negative—on AEP Ohio's cash working capital requirements to be established in a rate case.

In addition to these prominent features, witness Gabbard proposes a dollar-for-dollar Bad Debt Rider to be paid by customers. The rider not only provides AEP Ohio with a way to charge all its customers for competitive generation bad debt expense associated with the POR program, but also bad debt expense associated with distribution service and SSO generation customers, percentage of income payment plan ("PIPP") payments not collected through the universal service fund rider ("USF") and from customers net of any unused low-income credit funds. In the case of distribution service, witness Gabbard states that distribution base rates

[15] *Id.*, at 7.

[16] *Id.*, at 10.

already include $12.2 million that customers are paying for bad debt expense, and therefore the proposed rider includes only the bad debt expense over and above that base figure, until completion of the next base rate case. At that time, bad debt expense would be removed from base rates and charges to customers entirely through the rider. Late payment fees collected by AEP Ohio under its proposal would be a revenue credit to this rider.[17]

Q36. HAVE PURCHASE OF RECEIVABLE PROGRAMS BEEN PREVIOUSLY ADDRESSED BY THE OCC?

A36. Yes, they have. In comments submitted by the OCC in PUCO Case No. 12-3151-EL-COL, the OCC opposed POR programs. OCC opposed POR programs because it would impose costs on customers and may not produce more benefits for customers. OCC noted the lack of a demonstrated need for such programs to enhance retail competition. OCC also argued that the POR program causes customers to pay a regulatory subsidy to CRES providers, when regulatory subsidies are inappropriate in a deregulated market. In particular, revenue and bad debt expense reflect the normal business risks associated with the unregulated market.

I understand that the PUCO ruled that each electric distribution utility that does not currently offer a POR program should be encouraged to include such a

[17] *Id.*, at 9.

program in its next distribution case or SSO application. OCC Witness Jim Williams presents OCC's general position which is that AEP Ohio should not have a POR program. My testimony critiques the salient features of AEP Ohio's proposal, in the event that the PUCO decides to adopt a POR program in some form.

Q37. WHAT IS YOUR CONCLUSION CONCERNING THE SALIENT FEATURES OF AEP OHIO'S PROPOSAL?

A37. In the event the PUCO decides to authorize the Utility to implement a POR program as proposed in ESP III, I recommend the following:

- I agree that the implementation and ongoing program administrative charges should be paid for entirely by the CRES suppliers.
- I agree that the AEP Ohio payments to participating CRES providers should be designed to be "working capital neutral" such that no cash working capital due to the program needs to be included in the base rates that customers pay.
- I strongly oppose the Utility's proposal to purchase receivables at a zero discount and to instead charge retail customers for what otherwise would be the CRES suppliers' bad debt expense.

- It appears that AEP Ohio has linked the bad debt expense rider with the zero discount proposal. Hence, once the zero discount feature is removed, the bad debt expense rider is not needed and should not be adopted. Moreover, the bad debt expense rider is improper, because it improperly shifts risk away from the Utility (and CRES providers) and places it entirely onto customers. It is an inappropriate subsidy from customers to CRES providers.

Q38. DO YOU HAVE AN ALTERNATIVE RECOMMENDATION?

A38. Yes. I recommend that AEP Ohio's POR program proposal not be approved by the PUCO. If the PUCO concludes that a POR program is appropriate, it should incorporate a discount rate for Utility payments to CRES suppliers reflecting the Utility's actual or best estimate of the CRES commodity-related bad debt expense. This discount rate could be updated periodically based on actual experience with the program. The Utility's program should retain the proposed key features pertaining to collection of program costs from the participating CRES suppliers and being "working capital neutral."

In addition, I recommend that the PUCO protect customers by rejecting the proposed bad debt expense rider.

Q39. WHY DO YOU CONCLUDE THE PROPOSED BAD DEBT EXPENSE RIDER IS NOT NEEDED?

A39. If the PUCO adopts a POR and the zero discount rate feature is corrected to equal the actual bad debt expense, this rider would no longer be needed. The Utility's proposal in this case concerning SSO cost collection includes a cost reconciliation rider, i.e., SSO costs and customer revenues are to be trued up, dollar-for-dollar, and this mechanism could be designed to fully account for bad debt expense. As witness Gabbard points out, the Utility's base distribution rates already collect bad debt expense (i.e., the $12.2 million), as determined in the last rate case. This amount can be updated in accordance with the Utility's own decisions as to if and when to file base rate cases in accordance with its earnings position.

The introduction of this bad debt expense rider is an example of improper single issue ratemaking. The proposed bad debt rider is simply not needed.

I note that witness Gabbard implies that there is a linkage between the POR program discount rate level and the presence of a utility bad debt expense rider. At page 3 of his direct testimony (lines 17-19), witness Gabbard states:

> "Where POR programs are required, the discount rate is usually equal to the utility's uncollectable or bad debt rate. In that context, when a utility has a bad debt rider, the discount rate is usually zero, and the receivable is purchased at face value."

Q40. DOES WITNESS GABBARD ASSERT THERE ARE BENEFITS TO THE PROPOSED PURCHASE OF RECEIVABLES PROGRAM?

A40. Yes, witness Gabbard asserts that there are customer and other benefits associated with the proposed program, although the Utility has developed no quantification of the asserted program benefits. (See response to OCC INT-10-163.) The primary asserted benefit is that providing CRES suppliers with "a predictable revenue stream encourages [competitive retail] suppliers to market to customers in all customer classes, thus promoting an even more competitive Ohio Choice Market."[18] In other words, it is asserted that the program enhances retail competition in some manner, thereby expanding choice for customers and improving CRES supplier offers. Again, there is no quantification or even convincing documentation of this benefit. Mr. Gabbard's testimony goes on to list four other potential program benefits. These include benefits to customers, CRES suppliers and/or the Utility, and they largely take the form of what I would describe as administrative convenience and streamlining. For example, the program allows for budget or average monthly payment treatment for the customer's entire bill instead of just the "wires" portions of the bill; it simplifies bill payment for customers, etc. Again, there is no quantification of these asserted convenience and administrative streamlining types of benefits.[19]

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[18] *Id.*, at 4.

[19] *Id.*, at 5-6.

Q41. DO YOU AGREE WITH WITNESS GABBARD'S POSITION REGARDING THE ASSERTED BENEFITS OF THE POR PROGRAM?

A41. No. As stated above, it is not the purpose of my testimony to evaluate whether, in principle, a POR program, in combination with consolidated billing, can provide some administrative convenience and streamlining. Rather, I considered whether AEP Ohio's POR program proposal, with its zero discount, is beneficial, on balance, to customers. It is not. I am not able to find **any** substantiation or even argument in witness Gabbard's testimony that this listing of administrative convenience streamlining set of benefits requires the POR program to have a zero discount factor. Those same benefits would be available with the discount factor set at the actual CRES bad debt rate.

At pages 5-6 of his direct testimony, Mr. Gabbard lists half a dozen benefits to CRES suppliers that, presumably in his view, encourage them to participate in the market. He correctly states that the Utility's proposal provides CRES providers with greater revenue stability and certainty, along with some administrative savings. The problem with his presentation of CRES supplier benefits is that those same benefits would be present irrespective of the bad debt expense discount. A POR program with an appropriate and defined discount rate also provides CRES suppliers with those same qualitative benefits, but at a reasonable cost and not through the subsidy from customers that AEP Ohio's proposal would create. Again, his recitation of CRES supplier benefits does not support the zero discount proposal.

In addition, there is an implied assumption in Mr. Gabbard's presentation that the AEP Ohio retail market development is inadequate and that customers lack competitive alternatives. But there is no evidence presented that this is actually the case. In fact, at page 9 of his testimony, witness Gabbard acknowledges that "over half of AEP Ohio's customer load is now shopping and those numbers continue to increase." The response to OCC INT-10-190 states that, as of February 2014, there were 69 CRES suppliers registered in AEP Ohio's service territory, with 46 being active, and 29 serving multiple residential customers. This market development has taken place absent a POR program of any kind, let alone one with a zero discount factor. There is no evidence of a lack of robust retail market development or competitive choice, and thus no need to adopt a POR to address market development issues.

Q42. YOU STATE THAT A ZERO DISCOUNT IS NOT NEEDED FOR THE TYPE OF BENEFITS LISTED QUALITATIVELY IN MR. GABBARD'S TESTIMONY. HOWEVER, WOULDN'T A ZERO DISCOUNT PROVIDE GREATER CRES BENEFITS THAN SETTING THE DISCOUNT EQUAL TO THE BAD DEBT RATE, AS YOU SUGGEST?

A42. Yes. But those "benefits" would only be achieved through an AEP Ohio proposal for an outright subsidy, plain and simple, to the competitive retail market, to be paid for by utility customers. As Mr. Gabbard correctly states, AEP Ohio is held harmless under its proposal. Market logic and long-held experience dictate that subsidies to private suppliers induce greater supply as well as introducing the potential for market distortion. Subsidies are contrary to the notion of freely-functioning competitive markets. Indeed in an extreme sense, we could benefit and thereby promote CRES supplier activity even further by amending AEP Ohio's POR proposal to provide payments of 110 percent of billed receivables instead of just 100 percent. AEP Ohio's proposal provides an explicit subsidy to unregulated companies, and one that is arbitrary at that. Additionally, subsidies such as this are contrary to the policy of the state set forth in R.C. 4928.02(H).

I am not suggesting that subsidies to markets or suppliers can never be justified. There can be both economic and noneconomic arguments for subsidies both for social policy reasons and/or to correct market distortions.[20] But such arguments must be supported with a convincing public interest analysis and fully justified. The argument for a CRES supplier subsidy, paid by customers, has not been set forth by AEP Ohio and does not seem credible.

Q43. WILL CUSTOMERS BE HARMED BY AEP OHIO'S PURCHASE OF RECEIVABLES PROGRAM PROPOSAL?

A43. Yes, because customers must bear the actual bad debt expense (through the proposed bad debt expense rider). This charge should be rendered to a CRES supplier as a cost of doing business. A defender of the program might argue that competitive forces may lead CRES suppliers to reduce their price offers, thereby

[20] The economic case subsidies date back to the 18th century "infant industry" argument of Alexander Hamilton.

offsetting the customer-imposed cost of the bad debt rider. But there is no proof this would occur, and there is no guarantee that would occur.

This "no harm to customers" argument, however, assumes a fully developed competitive market where competition always drives price down to cost (inclusive of a competitively-required return). But if this were the case, then a POR program of any kind could not be justified to "jump start the market," let alone one with a large subsidy.

More realistically, CRES suppliers serving the retail market understand that, at least at this time, most residential customers continue to take SSO generation service. Consequently, to attract customers and increase market share, CRES suppliers must compete against the SSO (as well as each other) and therefore must offer a price that provides savings relative to the SSO rate in order to attract and/or retain customers. A POR program, with or without a subsidy in the discount rate, has no effect on the determination of the SSO price.[21] Consequently, there is no reason to be confident that CRES suppliers would reduce their price offers accordingly to flow through the bad debt expense subsidy paid by utility customers due to the AEP Ohio POR program.

[21] It is even possible that a highly subsidized POR program could increase SSO prices by creating uncertainty on the part of wholesale bidders in the Utility's DCAs. This is referred to as "volumetric risk," which is priced into the DCA bids.

The end result is an overall net increase in customer costs by the amount of the subsidy embedded in AEP Ohio's proposed POR program and bad debt expense rider. Moreover, this is not offset by witness Gabbard's list of administrative convenience/streamlining qualitative benefits because those benefits appear to be attainable without the zero discount feature and Bad Debt Rider.

Q44. PLEASE SUMMARIZE YOUR POSITION ON AEP OHIO'S PROPOSAL CONCERNING A POR PROGRAM.

A44. AEP Ohio has not shown the need or quantified any benefits for a POR program. However, if the PUCO is inclined to approve such a program for AEP Ohio:

- It should protect customers from subsidizing CRES suppliers and it instead should reflect a discount rate that includes AEP Ohio's actual or estimated bad debt expense, as periodically updated.
- It need not, nor should it, impose on customers a Bad Debt Rider.
- It should incorporate CRES supplier charges for POR program costs, as proposed by AEP Ohio.
- It should be "working capital neutral," to the extent feasible.

V. THE SSO POWER PROCUREMENT AND PRICING

A. The Standard Service Offer Competitive Procurement Process

Q45. HOW DOES THE UTILITY INTEND TO OBTAIN GENERATION SUPPLY TO SERVE ITS STANDARD SERVICE OFFER LOAD?

A45. Until recently, AEP Ohio operated as a vertically-integrated utility, supplying its SSO load from its owned generation, as well as energy from the wholesale market. The PUCO has authorized AEP Ohio to transfer its generation resources to an unregulated affiliate, with the exception of the OVEC contract, as discussed by OCC witness Wilson. It is my understanding that this authorized transfer has been completed. With this generation transfer, the Utility now must acquire the generation supply from the wholesale market to meet its SSO load requirements. While it is possible that AEP Ohio could use the retained OVEC contract to serve a portion of its SSO load, it proposes not to do so. Instead, the Utility proposes to charge all its customers (shopping and SSO alike) for the OVEC contract costs, sell the delivered OVEC supply into the PJM spot markets, and credit the revenues back to customers to offset the contract costs.

The Utility proposes to use a competitive process to acquire the power supply required to serve the SSO load, as described in detail in the direct testimony of Utility witness Dr. LaCasse. The proposed competitive process covers the entire three-year term of ESP III, June 2015 through May 2018, and involves six separate descending clock auctions spread out over three years. The products to be procured under the auctions are full requirements contracts ("FRCs") with terms of one and two years.

Q46. IS THE COMPETITIVE PROCESS DESCRIBED BY DR. LACASSE TYPICAL OF THOSE USED BY ELECTRIC DISTRIBUTION UTILITIES TO PROVIDE SSO GENERATION SERVICE?

A46. In general, yes, although the details can differ materially among utilities and states. Utilities typically use auctions or sealed-bid RFPs to procure generation supply competitively from the wholesale market. Regardless of which procurement method is used, wholesale supply is most often in the form of FRCs, that normally range in terms of one to three years. Utilities also follow the practice of procuring power to fill the required supply portfolio at multiple points in time, rather than a single procurement (e.g., one auction) in order to avoid or mitigate market timing risk. As noted, Dr. LaCasse proposes six separate auctions, two per year, to be conducted over three years.

Q47. WHAT ARE THE MAIN ATTRIBUTES OF THE DESCENDING CLOCK AUCTION?

A47. Under the descending clock auction structure, the default load is divided into "tranches" that wholesale suppliers may bid to serve. Each tranche is defined as a fixed percentage of AEP Ohio's total SSO load at each hour of the contract term. Dr. LaCasse suggests that the auction process will solicit service for 100 tranches, meaning that each tranche represents one percent of AEP Ohio's total hourly SSO load. If a supplier is awarded an FRC for ten tranches, for example, the supplier would be responsible for providing generation supply for 10 percent of the SSO load in every hour of the term of the FRC, regardless of the actual MW-size of the SSO load. The wholesale supplier's responsibility to serve load therefore will vary hourly in accordance with the "load shape" of SSO customers. It can also change over time, i.e., over the term of the FRC, as power demands of SSO customers change with economic conditions, weather, and other factors. More importantly, it also can change unpredictably with changes in the number of SSO customers, as customers migrate to or away from CRES providers. In other words, once the firm requirements contracts are awarded, the winning suppliers must accept all risks associated with changes in the total SSO load for the terms of those FRCs. It is also important to note that FRCs are fixed price (in dollars-per-MWh) for the full contract term. There are no price adjustments for changes in market conditions, and therefore, suppliers must manage this market risk.

The supply contracts are referred to as "full requirements" because the supplier is required to provide all necessary generation products "including energy, capacity, ancillary services, and certain transmission services."[22] The suppliers are also required to adhere to all PJM requirements. Under the FRCs, suppliers are paid a single "bundled" dollar-per-MWh price for generation supply, based on the

[22] LaCasse direct testimony, at 9.

auction clearing price for a given product. Suppliers are not paid separately (nor do they receive separate prices) for each individual generation product that they supply. Each descending clock auction will produce its own clearing price (or prices), and each product type (i.e., one- or two-year contract) within the same auction will have its own clearing price applicable to all winning suppliers in that auction.

Q48. DOES THE FULL REQUIREMENTS CONTRACT INCLUDE ALL NECESSARY TRANSMISSION?

A48. No. As Dr. LaCasse states, it only includes certain PJM transmission components that a wholesale generation supplier in PJM would incur (such as administrative fees associated with the PJM administered markets). AEP Ohio will charge its customers for "non-market" transmission. This is primarily the fixed costs (and related O&M expenses) associated with the transmission facilities located in the AEP Ohio transmission zone. The revenue requirements for these facilities are determined by PJM and approved by FERC under its cost of service regulation. These Utility transmission charges are totally separate from the FRCs and the competitive process described by Dr. LaCasse.

Q49. UNDER DR. LACASSE'S PROPOSAL, WHEN WILL THE AUCTIONS BE CONDUCTED?

A49. As shown on Dr. LaCasse's Exhibit CL-10, auctions will be conducted in September and March of each year, beginning in September 2014, with the final auction under ESP III in March 2017. For example, the auctions in September 2014 and March 2015 will provide 100 percent of supply for the first year of ESP III, which covers the June 1, 2015 to May 30, 2016 service year. These two auctions will procure 100 percent of the required tranches for that year.

Under the first two auctions, half the tranches procured will be one-year FRCs and half will be two-year firm requirement contracts. This means that a portion of the SSO load supply for year two of ESP III will be procured in those first two auctions. Under Dr. LaCasse's proposal, after the September 2014 and March 2015 auctions, all FRCs procured will have a term of one year. This means that for the entire three-year time period as a whole, about one-third of SSO load would be served under two-year firm requirement contracts, and about two-thirds would be served under one-year contracts. (The one-third is an estimate calculated as (50%+50%+0%)/3 = 33%.)[23]

While not addressed in its supporting testimony, AEP Ohio may be structuring SSO supply contracts in this way due to its proposed right to terminate ESP III after two years. This also may be the reason for not including any three-year

[23] At page 11 of her testimony, Dr. LaCasse states that the proposed portfolio would be about 2/3 one-year contracts and one-third two-year contracts. However, her Exhibit CL-10 seems to imply that this would just be in the first two years. If that is in fact her proposal, than over the full three years, only about 22 percent of SSO load would be served with two-year contracts, making the portfolio even more skewed. The Utility should clarify this ambiguity.

FRCs. The implications of the proposed two-year termination might have not been explained.

Q50. DR. LACASSE EXPLAINS IN HER TESTIMONY THAT THE PROPOSED COMPETITIVE BIDDING PROCESS FRAMEWORK MEETS THE STATUTORY REQUIREMENTS FOR AN MARKET RATE OFFER. DO YOU AGREE?

A50. I do not take issue with her assertion. At page 6 of her testimony, she lists the various statutory criteria that apply to an MRO, and she states that her recommended procurement process meets all of those requirements. In other words, the proposed ESP III would provide for SSO rates that are essentially the same as if AEP Ohio had only filed an MRO. AEP Ohio witness Allen and the Utility's responses to OCC INT-3-023 and OCC INT-3-024 concede the same point. The response to OCC INT-3-023 states:

> "The Company does not believe that the procurement methods, procedures, and/or products would need to change under the adoption of an MRO versus the Company's proposed ESP."

The response to OCC INT-3-024 states:

> "AEP Ohio's retail charges for the generation component of SSO rates could be the same under an ESP or an MRO."

The conclusion is that the AEP Ohio ESP III proposal provides no identified benefits relative to SSO generation costs and rates over and above what an MRO would provide.

Q51. DO YOU DISAGREE WITH ANY ASPECT OF DR. LACASSE'S PROCUREMENT PROCESS?

A51. Yes. While I believe the use of a mix of one-year and two-year firm requirement contracts is acceptable, I question the proposal to restrict the procurement of two-year contracts to the initial two auctions in September 2014 and March 2015. For the remaining four auctions, the Utility proposes that 100 percent of procurement will be one-year firm requirement contracts.

Q52. HAS DR. LACASSE PROVIDED ANY EXPLANATION FOR THE DISPROPORTIONATE RELIANCE ON ONE-YEAR FIRM REQUIREMENT CONTRACTS?

A52. OCC INT-3-031 questioned Dr. LaCasse on the proposed two-thirds/one-year, one-third/two-year contract mix. The response merely states that such a portfolio meets the criteria of being easy to understand and being clearly defined. It further states that it is responsive to potential market requirements (i.e., attractive to potential bidders) in that suppliers may have differing preferences concerning bidding to supply one-year versus two-year supply contracts. She provides no further substantiation.

Q53. IS THIS EXPLANATION ADEQUATE?

A53. Not entirely. I agree that her proposed supply portfolio is easy for suppliers to understand and solicits a well-defined product. Moreover, I concur that encouraging bidder participation contributes to a better pricing outcome for customers and is a valid criteria for designing the bid process. That said, her explanation does not substantiate having zero procurement of two-year contracts after the second auction (in March 2015), and having 100 percent of SSO supply in year three of the proposed ESP III from one-year contracts. In other words, the proposal is unduly skewed toward one-year contracts, and therefore may not be consistent with the goal of maximizing supplier participation.

Q54. ARE THERE ANY OTHER DISADVANTAGES TO THE PROPOSED PORTFOLIO?

A54. Yes. The portfolio design provides the potential for greater rate volatility than is necessary due to risks associated with market timing. Under the Utility's proposal, 100 percent of the supply would be procured for year one (i.e., the 12 months ending May 2016) on two days that are only about six months apart. This 100 percent procurement within a period of about six months is unavoidable at the outset of ESP III because AEP Ohio is transitioning away from self-supply to 100 percent market supply in its ESP III. In year two of the ESP III, Dr. LaCasse mitigates potential rate volatility because 50 percent of supply for that year will be from two-year firm requirement contracts acquired during the September 2014 and March 2015 auctions. That is, supply for year two will come from four auctions spread over about two years. At the end of year two, however, all of the two-year FRCs will expire, and AEP Ohio again would procure 100 percent of SSO supply from one-year contracts in two auctions about six months apart. Finally, all supply contracts expire on May 31, 2018, and there is no provision for any SSO supply at all after that date. This means that after year three, it seems inevitable that 100 percent of SSO supply for service beginning June 1, 2018, must be procured within a relatively short period of time, creating the potential for rate volatility.

This portfolio structure runs the risk of introducing more rate volatility than necessary, a problem that can be mitigated by having overlapping, multi-year supply contracts.

Q55. HAVE OTHER JURISDICTIONS ADDRESSED THIS ISSUE?

A55. Yes. Maryland procures two-year overlapping supply contracts for residential SSO load, with twice-per-year procurements. Under this portfolio, 25 percent of tranches are procured under two-year firm requirement contracts in each semi-annual procurement. New Jersey procures three-year overlapping supply contracts with one-third of tranches filled in each annual procurement as old contracts expire. These overlapping contract arrangements lessen potential rate volatility.

Q56. HAS THE PUCO EXPRESSED INTEREST IN FOSTERING LESS RATE VOLATILITY?

A56. Yes. In its 2012 ESP decision for the FirstEnergy utilities, the PUCO emphasized the importance of "laddering of products to smooth generation rates and provide price stability."[24]

Q57. DO YOU HAVE A PROPOSED MODIFICATION?

A57. Yes. A very simple remedy that would produce a 50/50 mix of one- and two-year contracts would involve changing the procurement in the fifth and sixth auctions. Instead of procuring 100 percent one-year contracts in those two auctions (for supply in year three of ESP III), the solicited products would be a 50/50 mix of one-year and two-year contracts. This would result in a SSO load being served by a portfolio consisting of one- and two-year contracts in all three years of ESP III. In addition, procuring two-year supply contracts in the last two auctions will provide contract overlap (and therefore lessen the potential for rate volatility) for the post-May 31, 2018 time period.

An alternative that the PUCO may wish to consider would be a 50/50 procurement mix of one- and two-year contracts in each of the six auctions. This

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[24] *In the Matter of Ohio Edison Company, the Cleveland Electric Illuminating Company, and the Toledo Edison Company for Authority to Provide for a Standard Service Offer Pursuant to Section 4928.143, Revised Code, in the form of an Electric Security Plan, Opinion and Order,* July 18, 2012, at 56.

would certainly be feasible and would help address rate volatility. It would also shift the portfolio to a greater than 50/50 weighting on two-year contracts.

B. Determination of Standard Service Offer Generation Supply Prices

Q58. DOES AEP OHIO PROPOSE TO SET RETAIL RATES FOR STANDARD SERVICE OFFER CUSTOMERS BASED ON THE BLENDED COSTS OF THE FIRM REQUIREMENT CONTRACTS PROCURED IN THE AUCTIONS?

A58. Yes it does, with certain adjustments and with the rates reset annually to reflect the expiration of old wholesale contracts and the start of new wholesale contracts. The pricing method also includes a dollar-for-dollar reconciliation charge to true-up the differences between supply costs incurred (including the expenses incurred in running the auctions) and customer revenues for SSO supply. The adjustments and pricing methodology are described in the testimony of AEP Ohio witness Roush.

Q59. WHAT ARE THE ADJUSTMENTS SET FORTH BY WITNESS ROUSH?

A59. There are three main adjustments to the wholesale blended FRC costs used to derive the customers' SSO retail rates. Line loss factors are applied to adjust (i.e., increase) the FRC costs from generator level to meter level. The loss factor varies by customer class because very large customers, such as large industrials, take service at higher voltages. Those large customers therefore have much lower loss factors. Next, prices are adjusted for a tax factor, 1.00435, which is the same factor for each customer class. Finally, Mr. Roush adjusts the power supply costs for each customer class based on imputing a capacity cost component of power supply. The development of this adjustment is shown on his Exhibit DMR-2.

Q60. PLEASE EXPLAIN HOW WITNESS ROUSH CALCULATES THIS THIRD ADJUSTMENT.

A60. At the outset, it must be noted that his adjustment calculations are only illustrative because the pricing results from the planned auctions are not yet available. Consequently, he has used the auction procurement prices obtained recently by another utility, Duke Energy Ohio, as a proxy. In addition, the SSO loads cannot be known and must be assumed, with AEP Ohio employing a volume of 17 million MWh per year, about 62 percent of that being residential.[25] As I noted earlier, the competitively-procured FRCs merely produce a blended dollars-per-MWh wholesale price. The supply contracts do not specify separate prices for the capacity, energy, and other generation subproducts. Mr. Roush calculates an implicit cost of capacity component for those wholesale contracts based on published PJM RPM capacity auction results. He converts that capacity price to a dollars-per-MWh value and subtracts that from the bundled and blended FRC price assumed to result from the planned DCAs. This produces implied, unbundled energy and capacity prices expressed in dollars-per-MWh.

[25] Roush Exhibit DMR-2, page 3 of 4. Line 5 shows residential sales of 10.5 million MWh per year out of a total of 17.0 million MWh.

Mr. Roush's next step is to determine what the implicit capacity price **should be** for each customer class. This is determined using customer class load factor data. For example, for year one of the ESP III, Mr. Roush's overall capacity price for SSO load is $11.48 per MWh but $14.51 for the residential class.[26] While a roughly $3 per MWh differential may not sound like much, given the more than 10 million MWh per year of residential SSO sales, this is a cost premium for the residential class of over $30 million for that one year.

Q61. WHAT IS THE END RESULT CUSTOMER CLASS PRICING UNDER MR. ROUSH'S METHODOLOGY?

A61. Accounting for all adjustments, his Exhibit DMR-2, page 4 of 4, shows a residential price of $56.20 per MWh, and a range of nonresidential customer class prices of $41.63 per MWh to $52.19 per MWh. All of these prices are for year one of ESP III. Using the data on his exhibit, I calculate an average SSO price for all classes combined of $53.37 and an average SSO price for the entire nonresidential SSO load of $48.74 per MWh. Thus, the residential premium relative to the overall SSO price is about 5.3 percent, and the residential premium compared to the overall nonresidential SSO price is 15.3 percent.

[26] *Id.*, line 6.

Q62. ARE THESE PRICING DIFFERENTIALS JUSTIFIED?

A62. No. I disagree, in part, with the procedure used. I do not question pricing differentials associated with loss factors since that is a physical reality and is consistent with the FRC structure. The wholesale suppliers under the FRCs are paid for their power supply deliveries effectively at the generation level, not the customer end-use meter level. My disagreement is charging residential customers a price premium for their load factor (Mr. Roush's capacity adjustment). This is an administratively-determined cost allocation technique, and it is not a result of the competitive procurement process. That is, setting aside line losses, there is nothing in the behavior of the bidders for the wholesale FRCs that demonstrates that there must be a price premium for residential customers.

Q63. ARE YOU STATING THAT WHOLESALE SUPPLIERS ARE INDIFFERENT TO THE CUSTOMER MIX OF SSO LOAD?

A63. No, that is not my position. All else equal, my view is that the low load factor for the residential customer class may well merit a pricing premium as compared to a higher load factor. The problem is with the "all else equal" assumption. There are two other critically important factors that affect pricing that Mr. Roush has not considered in setting class-specific rates. First, Dr. LaCasse discusses the importance of the size of the SSO load in the auction, with a large load attracting more bidders and therefore, more competition. Mr. Roush's method provides no recognition for the fact that the residential load accounts for about 62 percent of the total SSO load. Absent the residential class, the auctions would involve much smaller loads, and therefore may be less attractive to bidders.

A second, and even more important consideration is "migration risk," which I have previously discussed. The wholesale bidders are exposed to unpredictable load changes over the contract term due to customer migration to or from competitive service, and this is a very difficult risk to manage. This risk inevitably will be priced into their bids in the auctions. While all customer classes are permitted to (and do) migrate, nonresidential customers generally have a greater tendency to shop and, in that sense, are more "market sensitive." Residential customers over time may also move to competitive service, but such movements do not tend to be as abrupt. For example, for AEP Ohio, the majority of residential load at this time remains on the standard service offer. All of this suggests that, with respect to SSO load, wholesale suppliers may perceive less migration risk in serving the residential class. Hence, all else is not equal, and Mr. Roush's capacity adjustment price premium for residential customers may be contrary to wholesale market requirements under the FRC construct recommended by Dr. LaCasse. At a minimum, there is no showing by AEP Ohio that wholesale bidders in the auctions require a price premium to serve the residential class.

Q64. GIVEN YOUR OBSERVATIONS, WHAT DO YOU RECOMMEND?

A64. There are two possible remedies to this unwarranted price premium that AEP Ohio proposes to charge to residential customers. The most straightforward solution would be simply to not include the capacity adjustment in the customer class pricing since there is no showing that the market actually requires a price premium when risk factors are included. This would reduce the residential price in year one by about $3 per MWh, using Mr. Roush's data.

A market-based alternative would be to have a separate procurement for the residential class. This would not require a separate residential auction, but rather the auction could be conducted in the normal manner but with separate residential and nonresidential products identified. Bidders would then have the flexibility to submit bids for residential tranches and/or nonresidential tranches within the same auction. There would be separate clearing prices for residential and nonresidential FRCs, which would obviate the need for Mr. Roush's capacity adjustments.

I recognize this second, market-based alternative, while feasible, does introduce some complexity. In part, this is because some of the nonresidential customer classes have relatively small SSO loads, which may diminish further over time with migration. This raises a question as to whether there should be a single nonresidential product in the auction process or one for each class.

At this time, I submit the simpler and more pragmatic recommendation of simply eliminating Mr. Roush's capacity allocation pricing adjustment.

Q65. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A65. Yes, it does.

CERTIFICATE OF SERVICE

It is hereby certified that a true copy of the foregoing *Direct Testimony of Matthew I. Kahal on Behalf of The Ohio Consumers' Counsel* was served via electronic transmission this 6th day of May 2014.

/s/ Maureen R. Grady
Maureen R. Grady
Assistant Consumers' Counsel

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APPENDIX A

QUALIFICATIONS OF

MATTHEW I. KAHAL

MATTHEW I. KAHAL

Since 2001, Mr. Kahal has worked as an independent consulting economist, specializing in energy economics, public utility regulation, and utility financial studies. Over the past three decades, his work has encompassed electric utility integrated resource planning (IRP), power plant licensing, environmental compliance, and utility financial issues. In the financial area, he has conducted numerous cost of capital studies and addressed other financial issues for electric, gas, telephone, and water utilities. Mr. Kahal's work in recent years has expanded to electric power markets, mergers, and various aspects of regulation.

Mr. Kahal has provided expert testimony in approximately 400 cases before state and federal regulatory commissions, federal courts, and the U.S. Congress. His testimony has covered need for power, integrated resource planning, cost of capital, purchased power practices and contracts, merger economics, industry restructuring, and various other regulatory and public policy issues.

Education

B.A. (Economics) – University of Maryland, 1971

M.A. (Economics) – University of Maryland, 1974

Ph.D. candidacy – University of Maryland, completed all course work and qualifying examinations.

Previous Employment

1981-2001	Founding Principal, Vice President, and President Exeter Associates, Inc. Bethesda, MD
1980-1981	Member of the Economic Evaluation Directorate The Aerospace Corporation Washington, D.C.
1977-1980	Economist Washington, D.C. consulting firm
1972-1977	Research/Teaching Assistant and Instructor Department of Economics, University of Maryland (College Park) Lecturer in Business and Economics Montgomery College (Rockville, MD)

Professional Experience

Mr. Kahal has more than thirty years' experience managing and conducting consulting assignments relating to public utility economics and regulation. In 1981, he and five colleagues founded the firm of Exeter Associates, Inc., and for the next 20 years he served as a Principal and corporate officer of the firm. During that time, he supervised multi-million dollar support contracts with the State of Maryland and directed the technical work conducted by both Exeter professional staff and numerous subcontractors. Additionally, Mr. Kahal took the lead role at Exeter in consulting to the firm's other governmental and private clients in the areas of financial analysis, utility mergers, electric restructuring, and utility purchase power contracts.

At the Aerospace Corporation, Mr. Kahal served as an economic consultant to the Strategic Petroleum Reserve (SPR). In that capacity, he participated in a detailed financial assessment of the SPR, and developed an econometric forecasting model of U.S. petroleum industry inventories. That study has been used to determine the extent to which private sector petroleum stocks can be expected to protect the U.S. from the impacts of oil import interruptions.

Before entering consulting, Mr. Kahal held faculty positions with the Department of Economics at the University of Maryland and with Montgomery College, teaching courses on economic principles, business, and economic development.

Publications and Consulting Reports

Projected Electric Power Demands of the Baltimore Gas and Electric Company, Maryland Power Plant Siting Program, 1979.

Projected Electric Power Demands of the Allegheny Power System, Maryland Power Plant Siting Program, January 1980.

An Econometric Forecast of Electric Energy and Peak Demand on the Delmarva Peninsula, Maryland Power Plant Siting Program, March 1980 (with Ralph E. Miller).

A Benefit/Cost Methodology of the Marginal Cost Pricing of Tennessee Valley Authority Electricity, prepared for the Board of Directors of the Tennessee Valley Authority, April 1980.

An Evaluation of the Delmarva Power and Light Company Generating Capacity Profile and Expansion Plan, (Interim Report), prepared for the Delaware Office of the Public Advocate, July 1980 (with Sharon L. Mason).

Rhode Island-DOE Electric Utilities Demonstration Project, Third Interim Report on Preliminary Analysis of the Experimental Results, prepared for the Economic Regulatory Administration, U.S. Department of Energy, July 1980.

Petroleum Inventories and the Strategic Petroleum Reserve, The Aerospace Corporation, prepared for the Strategic Petroleum Reserve Office, U.S. Department of Energy, December 1980.
Alternatives to Central Station Coal and Nuclear Power Generation, prepared for Argonne National Laboratory and the Office of Utility Systems, U.S. Department of Energy, August 1981.

"An Econometric Methodology for Forecasting Power Demands," Conducting Need-for-Power Review for Nuclear Power Plants (D.A. Nash, ed.), U.S. Nuclear Regulatory Commission, NUREG-0942, December 1982.

State Regulatory Attitudes Toward Fuel Expense Issues, prepared for the Electric Power Research Institute, July 1983 (with Dale E. Swan).

"Problems in the Use of Econometric Methods in Load Forecasting," Adjusting to Regulatory, Pricing and Marketing Realities (Harry Trebing, ed.), Institute of Public Utilities, Michigan State University, 1983.

Proceedings of the Maryland Conference on Electric Load Forecasting (editor and contributing author), Maryland Power Plant Siting Program, PPES-83-4, October 1983.

"The Impacts of Utility-Sponsored Weatherization Programs: The Case of Maryland Utilities" (with others), in Government and Energy Policy (Richard L. Itteilag, ed.), 1983.

Power Plant Cumulative Environmental Impact Report, contributing author (Paul E. Miller, ed.) Maryland Department of Natural Resources, January 1984.

Projected Electric Power Demands for the Potomac Electric Power Company, three volumes (with Steven L. Estomin), prepared for the Maryland Power Plant Siting Program, March 1984.

"An Assessment of the State-of-the-Art of Gas Utility Load Forecasting" (with Thomas Bacon, Jr. and Steven L. Estomin), published in the Proceedings of the Fourth NARUC Biennial Regulatory Information Conference, 1984.

"Nuclear Power and Investor Perceptions of Risk" (with Ralph E. Miller), published in The Energy Industries in Transition: 1985-2000 (John P. Weyant and Dorothy Sheffield, eds.), 1984.

The Financial Impact of Potential Department of Energy Rate Recommendations on the Commonwealth Edison Company, prepared for the U.S. Department of Energy, October 1984.

"Discussion Comments," published in Impact of Deregulation and Market Forces on Public Utilities: The Future of Regulation (Harry Trebing, ed.), Institute of Public Utilities, Michigan State University, 1985.

An Econometric Forecast of the Electric Power Loads of Baltimore Gas and Electric Company, two volumes (with others), prepared for the Maryland Power Plant Siting Program, 1985.

A Survey and Evaluation of Demand Forecast Methods in the Gas Utility Industry, prepared for the Public Utilities Commission of Ohio, Forecasting Division, November 1985 (with Terence Manuel).

A Review and Evaluation of the Load Forecasts of Houston Lighting & Power Company and Central Power & Light Company – Past and Present, prepared for the Texas Public Utility Commission, December 1985 (with Marvin H. Kahn).

Power Plant Cumulative Environmental Impact Report for Maryland, principal author of three of the eight chapters in the report (Paul E. Miller, ed.), PPSP-CEIR-5, March 1986.

"Potential Emissions Reduction from Conservation, Load Management, and Alternative Power," published in Acid Deposition in Maryland: A Report to the Governor and General Assembly, Maryland Power Plant Research Program, AD-87-1, January 1987.

Determination of Retrofit Costs at the Oyster Creek Nuclear Generating Station, March 1988, prepared for Versar, Inc., New Jersey Department of Environmental Protection.

Excess Deferred Taxes and the Telephone Utility Industry, April 1988, prepared on behalf of the National Association of State Utility Consumer Advocates.

Toward a Proposed Federal Policy for Independent Power Producers, comments prepared on behalf of the Indiana Consumer Counselor, FERC Docket EL87-67-000, November 1987.

Review and Discussion of Regulations Governing Bidding Programs, prepared for the Pennsylvania Office of Consumer Advocate, June 1988.

A Review of the Proposed Revisions to the FERC Administrative Rules on Avoided Costs and Related Issues, prepared for the Pennsylvania Office of Consumer Advocate, April 1988.

Review and Comments on the FERC NOPR Concerning Independent Power Producers, prepared for the Pennsylvania Office of Consumer Advocate, June 1988.

The Costs to Maryland Utilities and Ratepayers of an Acid Rain Control Strategy – An Updated Analysis, prepared for the Maryland Power Plant Research Program, October 1987, AD-88-4.

"Comments," in New Regulatory and Management Strategies in a Changing Market Environment (Harry M. Trebing and Patrick C. Mann, editors), Proceedings of the Institute of Public Utilities Eighteenth Annual Conference, 1987.

Electric Power Resource Planning for the Potomac Electric Power Company, prepared for the Maryland Power Plant Research Program, July 1988.

Power Plant Cumulative Environmental Impact Report for Maryland (Thomas E. Magette, ed.), authored two chapters, November 1988, PPRP-CEIR-6.
Resource Planning and Competitive Bidding for Delmarva Power & Light Company, October 1990, prepared for the Maryland Department of Natural Resources (with M. Fullenbaum).

Electric Power Rate Increases and the Cleveland Area Economy, prepared for the Northeast Ohio Areawide Coordinating Agency, October 1988.

An Economic and Need for Power Evaluation of Baltimore Gas & Electric Company's Perryman Plant, May 1991, prepared for the Maryland Department of Natural Resources (with M. Fullenbaum).

The Cost of Equity Capital for the Bell Local Exchange Companies in a New Era of Regulation, October 1991, presented at the Atlantic Economic Society 32nd Conference, Washington, D.C.

A Need for Power Review of Delmarva Power & Light Company's Dorchester Unit 1 Power Plant, March 1993, prepared for the Maryland Department of National Resources (with M. Fullenbaum).

The AES Warrior Run Project: Impact on Western Maryland Economic Activity and Electric Rates, February 1993, prepared for the Maryland Power Plant Research Program (with Peter Hall).

An Economic Perspective on Competition and the Electric Utility Industry, November 1994, prepared for the Electric Consumers' Alliance.

PEPCO's Clean Air Act Compliance Plan: Status Report, prepared for the Maryland Power Plant Research Plan, January 1995 (w/Diane Mountain, Environmental Resources Management, Inc.).

The FERC Open Access Rulemaking: A Review of the Issues, prepared for the Indiana Office of Utility Consumer Counselor and the Pennsylvania Office of Consumer Advocate, June 1995.

A Status Report on Electric Utility Restructuring: Issues for Maryland, prepared for the Maryland Power Plant Research Program, November 1995 (with Daphne Psacharopoulos).

Modeling the Financial Impacts on the Bell Regional Holding Companies from Changes in Access Rates, prepared for MCI Corporation, May 1996.

The CSEF Electric Deregulation Study: Economic Miracle or the Economists' Cold Fusion?, prepared for the Electric Consumers' Alliance, Indianapolis, Indiana, October 1996.

Reducing Rates for Interstate Access Service: Financial Impacts on the Bell Regional Holding Companies, prepared for MCI Corporation, May 1997.

The New Hampshire Retail Competition Pilot Program: A Preliminary Evaluation, July 1997, prepared for the Electric Consumers' Alliance (with Jerome D. Mierzwa).

Electric Restructuring and the Environment: Issue Identification for Maryland, March 1997, prepared for the Maryland Power Plant Research Program (with Environmental Resource Management, Inc.).

An Analysis of Electric Utility Embedded Power Supply Costs, prepared for Power-Gen International Conference, Dallas, Texas, December 1997.

Market Power Outlook for Generation Supply in Louisiana, December 2000, prepared for the Louisiana Public Service Commission (with others).

A Review of Issues Concerning Electric Power Capacity Markets, prepared for the Maryland Power Plant Research Program, December 2001 (with B. Hobbs and J. Inon).
The Economic Feasibility of Air Emissions Controls at the Brandon Shores and Morgantown Coal-fired Power Plants, February 2005 (prepared for the Chesapeake Bay Foundation).

The Economic Feasibility of Power Plant Retirements on the Entergy System, September 2005, with Phil Hayet (prepared for the Louisiana Public Service Commission).

Expert Report on Capital Structure, Equity and Debt Costs, prepared for the Edmonton Regional Water Customers Group, August 30, 2006.

Maryland's Options to Reduce and Stabilize Electric Power Prices Following Restructuring, with Steven L. Estomin, prepared for the Power Plant Research Program, Maryland Department of Natural Resources, September 2006.

Expert Report of Matthew I. Kahal, on behalf of the U. S. Department of Justice, August 2008, Civil Action No. IP-99-1693C-MIS.

Conference and Workshop Presentations

Workshop on State Load Forecasting Programs, sponsored by the Nuclear Regulatory Commission and Oak Ridge National Laboratory, February 1982 (presentation on forecasting methodology).

Fourteenth Annual Conference of the Michigan State University Institute for Public Utilities, December 1982 (presentation on problems in forecasting).

Conference on Conservation and Load Management, sponsored by the Massachusetts Energy Facilities Siting Council, May 1983 (presentation on cost-benefit criteria).

Maryland Conference on Load Forecasting, sponsored by the Maryland Power Plant Siting Program and the Maryland Public Service Commission, June 1983 (presentation on overforecasting power demands).

The 5th Annual Meetings of the International Association of Energy Economists, June 1983 (presentation on evaluating weatherization programs).

The NARUC Advanced Regulatory Studies Program (presented lectures on capacity planning for electric utilities), February 1984.

The 16th Annual Conference of the Institute of Public Utilities, Michigan State University (discussant on phase-in and excess capacity), December 1984.

U.S. Department of Energy Utilities Conference, Las Vegas, Nevada (presentation of current and future regulatory issues), May 1985.

The 18th Annual Conference of the Institute of Public Utilities, Michigan State University, Williamsburg, Virginia, December 1986 (discussant on cogeneration).

The NRECA Conference on Load Forecasting, sponsored by the National Rural Electric Cooperative Association, New Orleans, Louisiana, December 1987 (presentation on load forecast accuracy).

The Second Rutgers/New Jersey Department of Commerce Annual Conference on Energy Policy in the Middle Atlantic States, Rutgers University, April 1988 (presentation on spot pricing of electricity).

The NASUCA 1988 Mid-Year Meeting, Annapolis, Maryland, June 1988, sponsored by the National Association of State Utility Consumer Advocates (presentation on the FERC electricity avoided cost NOPRs).

The Thirty-Second Atlantic Economic Society Conference, Washington, D.C., October 1991 (presentation of a paper on cost of capital issues for the Bell Operating Companies).

The NASUCA 1993 Mid-Year Meeting, St. Louis, Missouri, sponsored by the National Association of State Utility Consumer Advocates, June 1993 (presentation on regulatory issues concerning electric utility mergers).

The NASUCA and NARUC annual meetings in New York City, November 1993 (presentations and panel discussions on the emerging FERC policies on transmission pricing).

The NASUCA annual meetings in Reno, Nevada, November 1994 (presentation concerning the FERC NOPR on stranded cost recovery).

U.S. Department of Energy Utilities/Energy Management Workshop, March 1995 (presentation concerning electric utility competition).

The 1995 NASUCA Mid-Year Meeting, Breckenridge, Colorado, June 1995 (presentation concerning the FERC rulemaking on electric transmission open access).
The 1996 NASUCA Mid-Year Meeting, Chicago, Illinois, June 1996 (presentation concerning electric utility merger issues).

Conference on "Restructuring the Electric Industry," sponsored by the National Consumers League and Electric Consumers Alliance, Washington, D.C., May 1997 (presentation on retail access pilot programs).

The 1997 Mid-Atlantic Conference of Regulatory Utilities Commissioners (MARUC), Hot Springs, Virginia, July 1997 (presentation concerning electric deregulation issues).

Power-Gen '97 International Conference, Dallas, Texas, December 1997 (presentation concerning utility embedded costs of generation supply).

Consumer Summit on Electric Competition, sponsored by the National Consumers League and Electric Consumers' Alliance, Washington, D.C., March 2001 (presentation concerning generation supply and reliability).

National Association of State Utility Consumer Advocates, Mid-Year Meetings, Austin, Texas, June 16-17, 2002 (presenter and panelist on RTO/Standard Market Design issues).

Louisiana State Bar Association, Public Utility Section, Baton Rouge, Louisiana, October 2, 2002 (presentation on Performance-Based Ratemaking and panelist on RTO issues).

Virginia State Corporation Commission/Virginia State Bar, Twenty-Second National Regulatory Conference, Williamsburg, Virginia, May 10, 2004 (presentation on Electric Transmission System Planning).

APPENDIX B

LIST OF PAST TESTIMONY OF

MATTHEW I. KAHAL

1.	27374 & 27375 October 1978	Long Island Lighting Company	New York Counties	Nassau & Suffolk	Economic Impacts of Proposed Rate Increase
2.	6807 January 1978	Generic	Maryland	MD Power Plant Siting Program	Load Forecasting
3.	78-676-EL-AIR February 1978	Ohio Power Company	Ohio	Ohio Consumers' Counsel	Test Year Sales and Revenues
4.	17667 May 1979	Alabama Power Company	Alabama	Attorney General	Test Year Sales, Revenues, Costs, and Load Forecasts
5.	None April 1980	Tennessee Valley Authority	TVA Board	League of Women Voters	Time-of-Use Pricing
6.	R-80021082	West Penn Power Company	Pennsylvania	Office of Consumer Advocate	Load Forecasting, Marginal Cost pricing
7.	7259 (Phase I) October 1980	Potomac Edison Company	Maryland	MD Power Plant Siting Program	Load Forecasting
8.	7222 December 1980	Delmarva Power & Light Company	Maryland	MD Power Plant Siting Program	Need for Plant, Load Forecasting
9.	7441 June 1981	Potomac Electric Power Company	Maryland	Commission Staff	PURPA Standards
10.	7159 May 1980	Baltimore Gas & Electric	Maryland	Commission Staff	Time-of-Use Pricing
11.	81-044-E-42T	Monongahela Power	West Virginia	Commission Staff	Time-of-Use Rates
12.	7259 (Phase II) November 1981	Potomac Edison Company	Maryland	MD Power Plant Siting Program	Load Forecasting, Load Management
13.	1606 September 1981	Blackstone Valley Electric and Narragansett	Rhode Island	Division of Public Utilities	PURPA Standards
14.	RID 1819 April 1982	Pennsylvania Bell	Pennsylvania	Office of Consumer Advocate	Rate of Return
15.	82-0152 July 1982	Illinois Power Company	Illinois	U.S. Department of Defense	Rate of Return, CWIP

16.	7559 September 1982	Potomac Edison Company	Maryland	Commission Staff	Cogeneration
17.	820150-EU September 1982	Gulf Power Company	Florida	Federal Executive Agencies	Rate of Return, CWIP
18.	82-057-15 January 1983	Mountain Fuel Supply Company	Utah	Federal Executive Agencies	Rate of Return, Capital Structure
19.	5200 August 1983	Texas Electric Service Company	Texas	Federal Executive Agencies	Cost of Equity
20.	28069 August 1983	Oklahoma Natural Gas	Oklahoma	Federal Executive Agencies	Rate of Return, deferred taxes, capital structure, attrition
21.	83-0537 February 1984	Commonwealth Edison Company	Illinois	U.S. Department of Energy	Rate of Return, capital structure, financial capability
22.	84-035-01 June 1984	Utah Power & Light Company	Utah	Federal Executive Agencies	Rate of Return
23.	U-1009-137 July 1984	Utah Power & Light Company	Idaho	U.S. Department of Energy	Rate of Return, financial condition
24.	R-842590 August 1984	Philadelphia Electric Company	Pennsylvania	Office of Consumer Advocate	Rate of Return
25.	840086-EI August 1984	Gulf Power Company	Florida	Federal Executive Agencies	Rate of Return, CWIP
26.	84-122-E August 1984	Carolina Power & Light Company	South Carolina	South Carolina Consumer Advocate	Rate of Return, CWIP, load forecasting
27.	CGC-83-G & CGC-84-G October 1984	Columbia Gas of Ohio	Ohio	Ohio Division of Energy	Load forecasting
28.	R-842621 October 1984	Western Pennsylvania Water Company	Pennsylvania	Office of Consumer Advocate	Test year sales
29.	R-842710 January 1985	ALLTEL Pennsylvania Inc.	Pennsylvania	Office of Consumer Advocate	Rate of Return
30.	ER-504 February 1985	Allegheny Generating Company	FERC	Office of Consumer Advocate	Rate of Return

31.	R-842632 March 1985	West Penn Power Company	Pennsylvania	Office of Consumer Advocate	Rate of Return, conservation, time-of-use rates
32.	83-0537 & 84-0555 April 1985	Commonwealth Edison Company	Illinois	U.S. Department of Energy	Rate of Return, incentive rates, rate base
33.	Rulemaking Docket No. 11, May 1985	Generic	Delaware	Delaware Commission Staff	Interest rates on refunds
34.	29450 July 1985	Oklahoma Gas & Electric Company	Oklahoma	Oklahoma Attorney General	Rate of Return, CWIP in rate base
35.	1811 August 1985	Bristol County Water Company	Rhode Island	Division of Public Utilities	Rate of Return, capital Structure
36.	R-850044 & R-850045 August 1985	Quaker State & Continental Telephone Companies	Pennsylvania	Office of Consumer Advocate	Rate of Return
37.	R-850174 November 1985	Philadelphia Suburban Water Company	Pennsylvania	Office of Consumer Advocate	Rate of Return, financial conditions
38.	U-1006-265 March 1986	Idaho Power Company	Idaho	U.S. Department of Energy	Power supply costs and models
39.	EL-86-37 & EL-86-38 September 1986	Allegheny Generating Company	FERC	PA Office of Consumer Advocate	Rate of Return
40.	R-850287 June 1986	National Fuel Gas Distribution Corp.	Pennsylvania	Office of Consumer Advocate	Rate of Return
41.	1849 August 1986	Blackstone Valley Electric	Rhode Island	Division of Public Utilities	Rate of Return, financial condition
42.	86-297-GA-AIR November 1986	East Ohio Gas Company	Ohio	Ohio Consumers' Counsel	Rate of Return
43.	U-16945 December 1986	Louisiana Power & Light Company	Louisiana	Public Service Commission	Rate of Return, rate phase-in plan
44.	Case No. 7972 February 1987	Potomac Electric Power Company	Maryland	Commission Staff	Generation capacity planning, purchased power contract
45.	EL-86-58 & EL-86-59 March 1987	System Energy Resources and Middle South Services	FERC	Louisiana PSC	Rate of Return

46.	ER-87-72-001 April 1987	Orange & Rockland	FERC	PA Office of Consumer Advocate	Rate of Return
47.	U-16945 April 1987	Louisiana Power & Light Company	Louisiana	Commission Staff	Revenue requirement update phase-in plan
48.	P-870196 May 1987	Pennsylvania Electric Company	Pennsylvania	Office of Consumer Advocate	Cogeneration contract
49.	86-2025-EL-AIR June 1987	Cleveland Electric Illuminating Company	Ohio	Ohio Consumers' Counsel	Rate of Return
50.	86-2026-EL-AIR June 1987	Toledo Edison Company	Ohio	Ohio Consumers' Counsel	Rate of Return
51.	87-4 June 1987	Delmarva Power & Light Company	Delaware	Commission Staff	Cogeneration/small power
52.	1872 July 1987	Newport Electric Company	Rhode Island	Commission Staff	Rate of Return
53.	WO 8606654 July 1987	Atlantic City Sewerage Company	New Jersey	Resorts International	Financial condition
54.	7510 August 1987	West Texas Utilities Company	Texas	Federal Executive Agencies	Rate of Return, phase-in
55.	8063 Phase I October 1987	Potomac Electric Power Company	Maryland	Power Plant Research Program	Economics of power plant site selection
56.	00439 November 1987	Oklahoma Gas & Electric Company	Oklahoma	Smith Cogeneration	Cogeneration economics
57.	RP-87-103 February 1988	Panhandle Eastern Pipe Line Company	FERC	Indiana Utility Consumer Counselor	Rate of Return
58.	EC-88-2-000 February 1988	Utah Power & Light Co. PacifiCorp	FERC	Nucor Steel	Merger economics
59.	87-0427 February 1988	Commonwealth Edison Company	Illinois	Federal Executive Agencies	Financial projections
60.	870840 February 1988	Philadelphia Suburban Water Company	Pennsylvania	Office of Consumer Advocate	Rate of Return

61.	870832 March 1988	Columbia Gas of Pennsylvania	Pennsylvania	Office of Consumer Advocate	Rate of Return
62.	8063 Phase II July 1988	Potomac Electric Power Company	Maryland	Power Plant Research Program	Power supply study
63.	8102 July 1988	Southern Maryland Electric Cooperative	Maryland	Power Plant Research Program	Power supply study
64.	10105 August 1988	South Central Bell Telephone Co.	Kentucky	Attorney General	Rate of Return, incentive regulation
65.	00345 August 1988	Oklahoma Gas & Electric Company	Oklahoma	Smith Cogeneration	Need for power
66.	U-17906 September 1988	Louisiana Power & Light Company	Louisiana	Commission Staff	Rate of Return, nuclear power costs Industrial contracts
67.	88-170-EL-AIR October 1988	Cleveland Electric Illuminating Co.	Ohio	Northeast-Ohio Areawide Coordinating Agency	Economic impact study
68.	1914 December 1988	Providence Gas Company	Rhode Island	Commission Staff	Rate of Return
69.	U-12636 & U-17649 February 1989	Louisiana Power & Light Company	Louisiana	Commission Staff	Disposition of litigation proceeds
70.	00345 February 1989	Oklahoma Gas & Electric Company	Oklahoma	Smith Cogeneration	Load forecasting
71.	RP88-209 March 1989	Natural Gas Pipeline of America	FERC	Indiana Utility Consumer Counselor	Rate of Return
72.	8425 March 1989	Houston Lighting & Power Company	Texas	U.S. Department of Energy	Rate of Return
73.	EL89-30-000 April 1989	Central Illinois Public Service Company	FERC	Soyland Power Coop, Inc.	Rate of Return
74.	R-891208 May 1989	Pennsylvania American Water Company	Pennsylvania	Office of Consumer Advocate	Rate of Return

75.	89-0033 May 1989	Illinois Bell Telephone Company	Illinois	Citizens Utility Board	Rate of Return
76.	881167-EI May 1989	Gulf Power Company	Florida	Federal Executive Agencies	Rate of Return
77.	R-891218 July 1989	National Fuel Gas Distribution Company	Pennsylvania	Office of Consumer Advocate	Sales forecasting
78.	8063, Phase III Sept. 1989	Potomac Electric Power Company	Maryland	Depart. Natural Resources	Emissions Controls
79.	37414-S2 October 1989	Public Service Company of Indiana	Indiana	Utility Consumer Counselor	Rate of Return, DSM, off-system sales, incentive regulation
80.	October 1989	Generic	U.S. House of Reps. Comm. on Ways & Means	N/A	Excess deferred income tax
81.	38728 November 1989	Indiana Michigan Power Company	Indiana	Utility Consumer Counselor	Rate of Return
82.	RP89-49-000 December 1989	National Fuel Gas Supply Corporation	FERC	PA Office of Consumer Advocate	Rate of Return
83.	R-891364 December 1989	Philadelphia Electric Company	Pennsylvania	PA Office of Consumer Advocate	Financial impacts (surrebuttal only)
84.	RP89-160-000 January 1990	Trunkline Gas Company	FERC	Indiana Utility Consumer Counselor	Rate of Return
85.	EL90-16-000 November 1990	System Energy Resources, Inc.	FERC	Louisiana Public Service Commission	Rate of Return
86.	89-624 March 1990	Bell Atlantic	FCC	PA Office of Consumer Advocate	Rate of Return
87.	8245 March 1990	Potomac Edison Company	Maryland	Depart. Natural Resources	Avoided Cost
88.	000586 March 1990	Public Service Company of Oklahoma	Oklahoma	Smith Cogeneration Mgmt.	Need for Power

89.	38868 March 1990	Indianapolis Water Company	Indiana	Utility Consumer Counselor	Rate of Return
90.	1946 March 1990	Blackstone Valley Electric Company	Rhode Island	Division of Public Utilities	Rate of Return
91.	000776 April 1990	Oklahoma Gas & Electric Company	Oklahoma	Smith Cogeneration Mgmt.	Need for Power
92.	890366 May 1990, December 1990	Metropolitan Edison Company	Pennsylvania	Office of Consumer Advocate	Competitive Bidding Program Avoided Costs
93.	EC-90-10-000 May 1990	Northeast Utilities	FERC	Maine PUC, et al.	Merger, Market Power, Transmission Access
94.	ER-891109125 July 1990	Jersey Central Power & Light	New Jersey	Rate Counsel	Rate of Return
95.	R-901670 July 1990	National Fuel Gas Distribution Corp.	Pennsylvania	Office of Consumer Advocate	Rate of Return Test year sales
96.	8201 October 1990	Delmarva Power & Light Company	Maryland	Depart. Natural Resources	Competitive Bidding, Resource Planning
97.	EL90-45-000 April 1991	Entergy Services, Inc.	FERC	Louisiana PSC	Rate of Return
98.	GR90080786J January 1991	New Jersey Natural Gas	New Jersey	Rate Counsel	Rate of Return
99.	90-256 January 1991	South Central Bell Telephone Company	Kentucky	Attorney General	Rate of Return
100.	U-17949A February 1991	South Central Bell Telephone Company	Louisiana	Louisiana PSC	Rate of Return
101.	ER90091090J April 1991	Atlantic City Electric Company	New Jersey	Rate Counsel	Rate of Return
102.	8241, Phase I April 1991	Baltimore Gas & Electric Company	Maryland	Dept. of Natural Resources	Environmental controls

103.	8241, Phase II May 1991	Baltimore Gas & Electric Company	Maryland	Dept. of Natural Resources	Need for Power, Resource Planning
104.	39128 May 1991	Indianapolis Water Company	Indiana	Utility Consumer Counselor	Rate of Return, rate base, financial planning
105.	P-900485 May 1991	Duquesne Light Company	Pennsylvania	Office of Consumer Advocate	Purchased power contract and related ratemaking
106.	G900240 P910502 May 1991	Metropolitan Edison Company Pennsylvania Electric Company	Pennsylvania	Office of Consumer Advocate	Purchased power contract and related ratemaking
107.	GR901213915 May 1991	Elizabethtown Gas Company	New Jersey	Rate Counsel	Rate of Return
108.	91-5032 August 1991	Nevada Power Company	Nevada	U.S. Dept. of Energy	Rate of Return
109.	EL90-48-000 November 1991	Entergy Services	FERC	Louisiana PSC	Capacity transfer
110.	000662 September 1991	Southwestern Bell Telephone	Oklahoma	Attorney General	Rate of Return
111.	U-19236 October 1991	Arkansas Louisiana Gas Company	Louisiana	Louisiana PSC Staff	Rate of Return
112.	U-19237 December 1991	Louisiana Gas Service Company	Louisiana	Louisiana PSC Staff	Rate of Return
113.	ER91030356J October 1991	Rockland Electric Company	New Jersey	Rate Counsel	Rate of Return
114.	GR91071243J February 1992	South Jersey Gas Company	New Jersey	Rate Counsel	Rate of Return
115.	GR91081393J March 1992	New Jersey Natural Gas Company	New Jersey	Rate Counsel	Rate of Return
116.	P-870235, et al. March 1992	Pennsylvania Electric Company	Pennsylvania	Office of Consumer Advocate	Cogeneration contracts

117.	8413 March 1992	Potomac Electric Power Company	Maryland	Dept. of Natural Resources	IPP purchased power contracts
118.	39236 March 1992	Indianapolis Power & Light Company	Indiana	Utility Consumer Counselor	Least-cost planning Need for power
119.	R-912164 April 1992	Equitable Gas Company	Pennsylvania	Office of Consumer Advocate	Rate of Return
120.	ER-91111698J May 1992	Public Service Electric & Gas Company	New Jersey	Rate Counsel	Rate of Return
121.	U-19631 June 1992	Trans Louisiana Gas Company	Louisiana	PSC Staff	Rate of Return
122.	ER-91121820J July 1992	Jersey Central Power & Light Company	New Jersey	Rate Counsel	Rate of Return
123.	R-00922314 August 1992	Metropolitan Edison Company	Pennsylvania	Office of Consumer Advocate	Rate of Return
124.	92-049-05 September 1992	US West Communications	Utah	Committee of Consumer Services	Rate of Return
125.	92PUE0037 September 1992	Commonwealth Gas Company	Virginia	Attorney General	Rate of Return
126.	EC92-21-000 September 1992	Entergy Services, Inc.	FERC	Louisiana PSC	Merger Impacts (Affidavit)
127.	ER92-341-000 December 1992	System Energy Resources	FERC	Louisiana PSC	Rate of Return
128.	U-19904 November 1992	Louisiana Power & Light Company	Louisiana	Staff	Merger analysis, competition competition issues
129.	8473 November 1992	Baltimore Gas & Electric Company	Maryland	Dept. of Natural Resources	QF contract evaluation
130.	IPC-E-92-25 January 1993	Idaho Power Company	Idaho	Federal Executive Agencies	Power Supply Clause

131.	E002/GR-92-1185 February 1993	Northern States Power Company	Minnesota	Attorney General	Rate of Return
132.	92-102, Phase II March 1992	Central Maine Power Company	Maine	Staff	QF contracts prudence and procurements practices
133.	EC92-21-000 March 1993	Entergy Corporation	FERC	Louisiana PSC	Merger Issues
134.	8489 March 1993	Delmarva Power & Light Company	Maryland	Dept. of Natural Resources	Power Plant Certification
135.	11735 April 1993	Texas Electric Utilities Company	Texas	Federal Executives Agencies	Rate of Return
136.	2082 May 1993	Providence Gas Company	Rhode Island	Division of Public Utilities	Rate of Return
137.	P-00930715 December 1993	Bell Telephone Company of Pennsylvania	Pennsylvania	Office of Consumer Advocate	Rate of Return, Financial Projections, Bell/TCI merger
138.	R-00932670 February 1994	Pennsylvania-American Water Company	Pennsylvania	Office of Consumer Advocate	Rate of Return
139.	8583 February 1994	Conowingo Power Company	Maryland	Dept. of Natural Resources	Competitive Bidding for Power Supplies
140.	E-015/GR-94-001 April 1994	Minnesota Power & Light Company	Minnesota	Attorney General	Rate of Return
141.	CC Docket No. 94-1 May 1994	Generic Telephone	FCC	MCI Comm. Corp.	Rate of Return
142.	92-345, Phase II June 1994	Central Maine Power Company	Maine	Advocacy Staff	Price Cap Regulation Fuel Costs
143.	93-11065 April 1994	Nevada Power Company	Nevada	Federal Executive Agencies	Rate of Return
144.	94-0065 May 1994	Commonwealth Edison Company	Illinois	Federal Executive Agencies	Rate of Return
145.	GR94010002J June 1994	South Jersey Gas Company	New Jersey	Rate Counsel	Rate of Return

146.	WR94030059 July 1994	New Jersey-American Water Company	New Jersey	Rate Counsel	Rate of Return
147.	RP91-203-000 June 1994	Tennessee Gas Pipeline Company	FERC	Customer Group	Environmental Externalities (oral testimony only)
148.	ER94-998-000 July 1994	Ocean State Power	FERC	Boston Edison Company	Rate of Return
149.	R-00942986 July 1994	West Penn Power Company	Pennsylvania	Office of Consumer Advocate	Rate of Return, Emission Allowances
150.	94-121 August 1994	South Central Bell Telephone Company	Kentucky	Attorney General	Rate of Return
151.	35854-S2 November 1994	PSI Energy, Inc.	Indiana	Utility Consumer Counsel	Merger Savings and Allocations
152.	IPC-E-94-5 November 1994	Idaho Power Company	Idaho	Federal Executive Agencies	Rate of Return
153.	November 1994	Edmonton Water	Alberta, Canada	Regional Customer Group	Rate of Return (Rebuttal Only)
154.	90-256 December 1994	South Central Bell Telephone Company	Kentucky	Attorney General	Incentive Plan True-Ups
155.	U-20925 February 1995	Louisiana Power & Light Company	Louisiana	PSC Staff	Rate of Return Industrial Contracts Trust Fund Earnings
156.	R-00943231 February 1995	Pennsylvania-American Water Company	Pennsylvania	Consumer Advocate	Rate of Return
157.	8678 March 1995	Generic	Maryland	Dept. Natural Resources	Electric Competition Incentive Regulation (oral only)
158.	R-000943271 April 1995	Pennsylvania Power & Light Company	Pennsylvania	Consumer Advocate	Rate of Return Nuclear decommissioning Capacity Issues
159.	U-20925 May 1995	Louisiana Power & Light Company	Louisiana	Commission Staff	Class Cost of Service Issues

160.	2290 June 1995	Narragansett Electric Company	Rhode Island	Division Staff	Rate of Return
161.	U-17949E June 1995	South Central Bell Telephone Company	Louisiana	Commission Staff	Rate of Return
162.	2304 July 1995	Providence Water Supply Board	Rhode Island	Division Staff	Cost recovery of Capital Spending Program
163.	ER95-625-000, et al. August 1995	PSI Energy, Inc.	FERC	Office of Utility Consumer Counselor	Rate of Return
164.	P-00950915, et al. September 1995	Paxton Creek Cogeneration Assoc.	Pennsylvania	Office of Consumer Advocate	Cogeneration Contract Amendment
165.	8702 September 1995	Potomac Edison Company	Maryland	Dept. of Natural Resources	Allocation of DSM Costs (oral only)
166.	ER95-533-001 September 1995	Ocean State Power	FERC	Boston Edison Co.	Cost of Equity
167.	40003 November 1995	PSI Energy, Inc.	Indiana	Utility Consumer Counselor	Rate of Return Retail wheeling
168.	P-55, SUB 1013 January 1996	BellSouth	North Carolina	AT&T	Rate of Return
169.	P-7, SUB 825 January 1996	Carolina Tel.	North Carolina	AT&T	Rate of Return
170.	February 1996	Generic Telephone	FCC	MCI	Cost of capital
171.	95A-531EG April 1996	Public Service Company of Colorado	Colorado	Federal Executive Agencies	Merger issues
172.	ER96-399-000 May 1996	Northern Indiana Public Service Company	FERC	Indiana Office of Utility Consumer Counselor	Cost of capital
173.	8716 June 1996	Delmarva Power & Light Company	Maryland	Dept. of Natural Resources	DSM programs
174.	8725 July 1996	BGE/PEPCO	Maryland	Md. Energy Admin.	Merger Issues

175.	U-20925 August 1996	Entergy Louisiana, Inc.	Louisiana	PSC Staff	Rate of Return Allocations Fuel Clause
176.	EC96-10-000 September 1996	BGE/PEPCO	FERC	Md. Energy Admin.	Merger issues competition
177.	EL95-53-000 November 1996	Entergy Services, Inc.	FERC	Louisiana PSC	Nuclear Decommissioning
178.	WR96100768 March 1997	Consumers NJ Water Company	New Jersey	Ratepayer Advocate	Cost of Capital
179.	WR96110818 April 1997	Middlesex Water Co.	New Jersey	Ratepayer Advocate	Cost of Capital
180.	U-11366 April 1997	Ameritech Michigan	Michigan	MCI	Access charge reform/financial condition
181.	97-074 May 1997	BellSouth	Kentucky	MCI	Rate Rebalancing financial condition
182.	2540 June 1997	New England Power	Rhode Island	PUC Staff	Divestiture Plan
183.	96-336-TP-CSS June 1997	Ameritech Ohio	Ohio	MCI	Access Charge reform Economic impacts
184.	WR97010052 July 1997	Maxim Sewerage Corp.	New Jersey	Ratepayer Advocate	Rate of Return
185.	97-300 August 1997	LG&E/KU	Kentucky	Attorney General	Merger Plan
186.	Case No. 8738 August 1997	Generic (oral testimony only)	Maryland	Dept. of Natural Resources	Electric Restructuring Policy
187.	Docket No. 2592 September 1997	Eastern Utilities	Rhode Island	PUC Staff	Generation Divestiture
188.	Case No.97-247 September 1997	Cincinnati Bell Telephone	Kentucky	MCI	Financial Condition

189.	Docket No. U-20925 November 1997	Entergy Louisiana	Louisiana	PSC Staff	Rate of Return
190.	Docket No. D97.7.90 November 1997	Montana Power Co.	Montana	Montana Consumers Counsel	Stranded Cost
191.	Docket No. EO97070459 November 1997	Jersey Central Power & Light Co.	New Jersey	Ratepayer Advocate	Stranded Cost
192.	Docket No. R-00974104 November 1997	Duquesne Light Co.	Pennsylvania	Office of Consumer Advocate	Stranded Cost
193.	Docket No. R-00973981 November 1997	West Penn Power Co.	Pennsylvania	Office of Consumer Advocate	Stranded Cost
194.	Docket No. A-1101150F0015 November 1997	Allegheny Power System DQE, Inc.	Pennsylvania	Office of Consumer Advocate	Merger Issues
195.	Docket No. WR97080615 January 1998	Consumers NJ Water Company	New Jersey	Ratepayer Advocate	Rate of Return
196.	Docket No. R-00974149 January 1998	Pennsylvania Power Company	Pennsylvania	Office of Consumer Advocate	Stranded Cost
197.	Case No. 8774 January 1998	Allegheny Power System DQE, Inc.	Maryland	Dept. of Natural Resources MD Energy Administration	Merger Issues
198.	Docket No. U-20925 (SC) March 1998	Entergy Louisiana, Inc.	Louisiana	Commission Staff	Restructuring, Stranded Costs, Market Prices
199.	Docket No. U-22092 (SC) March 1998	Entergy Gulf States, Inc.	Louisiana	Commission Staff	Restructuring, Stranded Costs, Market Prices
200.	Docket Nos. U-22092 (SC) and U-20925(SC) May 1998	Entergy Gulf States and Entergy Louisiana	Louisiana	Commission Staff	Standby Rates
201.	Docket No. WR98010015 May 1998	NJ American Water Co.	New Jersey	Ratepayer Advocate	Rate of Return
202.	Case No. 8794 December 1998	Baltimore Gas & Electric Co.	Maryland	MD Energy Admin./Dept. Of Natural Resources	Stranded Cost/ Transition Plan

203.	Case No. 8795 December 1998	Delmarva Power & Light Co.	Maryland	MD Energy Admin./Dept. Of Natural Resources	Stranded Cost/ Transition Plan
204.	Case No. 8797 January 1998	Potomac Edison Co.	Maryland	MD Energy Admin./Dept. Of Natural Resources	Stranded Cost/ Transition Plan
205.	Docket No. WR98090795 March 1999	Middlesex Water Co.	New Jersey	Ratepayer Advocate	Rate of Return
206.	Docket No. 99-02-05 April 1999	Connecticut Light & Power	Connecticut	Attorney General	Stranded Costs
207.	Docket No. 99-03-04 May 1999	United Illuminating Company	Connecticut	Attorney General	Stranded Costs
208.	Docket No. U-20925 (FRP) June 1999	Entergy Louisiana, Inc.	Louisiana	Staff	Capital Structure
209.	Docket No. EC-98-40-000, et al. May 1999	American Electric Power/ Central & Southwest	FERC	Arkansas PSC	Market Power Mitigation
210.	Docket No. 99-03-35 July 1999	United Illuminating Company	Connecticut	Attorney General	Restructuring
211.	Docket No. 99-03-36 July 1999	Connecticut Light & Power Co.	Connecticut	Attorney General	Restructuring
212.	WR99040249 Oct. 1999	Environmental Disposal Corp.	New Jersey	Ratepayer Advocate	Rate of Return
213.	2930 Nov. 1999	NEES/EUA	Rhode Island	Division Staff	Merger/Cost of Capital
214.	DE99-099 Nov. 1999	Public Service New Hampshire	New Hampshire	Consumer Advocate	Cost of Capital Issues
215.	00-01-11 Feb. 2000	Con Ed/NU	Connecticut	Attorney General	Merger Issues
216.	Case No. 8821 May 2000	Reliant/ODEC	Maryland	Dept. of Natural Resources	Need for Power/Plant Operations

217.	Case No. 8738 July 2000	Generic	Maryland	Dept. of Natural Resources	DSM Funding
218.	Case No. U-23356 June 2000	Entergy Louisiana, Inc.	Louisiana	PSC Staff	Fuel Prudence Issues Purchased Power
219.	Case No. 21453, et al. July 2000	SWEPCO	Louisiana	PSC Staff	Stranded Costs
220.	Case No. 20925 (B) July 2000	Entergy Louisiana	Louisiana	PSC Staff	Purchase Power Contracts
221.	Case No. 24889 August 2000	Entergy Louisiana	Louisiana	PSC Staff	Purchase Power Contracts
222.	Case No. 21453, et al. February 2001	CLECO	Louisiana	PSC Staff	Stranded Costs
223.	P-00001860 and P-0000181 March 2001	GPU Companies	Pennsylvania	Office of Consumer Advocate	Rate of Return
224.	CVOL-0505662-S March 2001	ConEd/NU	Connecticut Superior Court	Attorney General	Merger (Affidavit)
225.	U-20925 (SC) March 2001	Entergy Louisiana	Louisiana	PSC Staff	Stranded Costs
226.	U-22092 (SC) March 2001	Entergy Gulf States	Louisiana	PSC Staff	Stranded Costs
227.	U-25533 May 2001	Entergy Louisiana/ Gulf States	Louisiana Interruptible Service	PSC Staff	Purchase Power
228.	P-00011872 May 2001	Pike County Pike	Pennsylvania	Office of Consumer Advocate	Rate of Return
229.	8893 July 2001	Baltimore Gas & Electric Co.	Maryland	MD Energy Administration	Corporate Restructuring
230.	8890 September 2001	Potomac Electric/Connectivity	Maryland	MD Energy Administration	Merger Issues

231.	U-25533 August 2001	Entergy Louisiana / Gulf States	Louisiana	Staff	Purchase Power Contracts
232.	U-25965 November 2001	Generic	Louisiana	Staff	RTO Issues
233.	3401 March 2002	New England Gas Co.	Rhode Island	Division of Public Utilities	Rate of Return
234.	99-833-MJR April 2002	Illinois Power Co.	U.S. District Court	U.S. Department of Justice	New Source Review
235.	U-25533 March 2002	Entergy Louisiana/ Gulf States	Louisiana	PSC Staff	Nuclear Uprates Purchase Power
236.	P-00011872 May 2002	Pike County Power & Light	Pennsylvania	Consumer Advocate	POLR Service Costs
237.	U-26361, Phase I May 2002	Entergy Louisiana/ Gulf States	Louisiana	PSC Staff	Purchase Power Cost Allocations
238.	R-00016849C001, et al. June 2002	Generic	Pennsylvania	Pennsylvania OCA	Rate of Return
239.	U-26361, Phase II July 2002	Entergy Louisiana/ Entergy Gulf States	Louisiana	PSC Staff	Purchase Power Contracts
240.	U-20925(B) August 2002	Entergy Louisiana	Louisiana	PSC Staff	Tax Issues
241.	U-26531 October 2002	SWEPCO	Louisiana	PSC Staff	Purchase Power Contract
242.	8936 October 2002	Delmarva Power & Light	Maryland	Energy Administration Dept. Natural Resources	Standard Offer Service
243.	U-25965 November 2002	SWEPCO/AEP	Louisiana	PSC Staff	RTO Cost/Benefit
244.	8908 Phase I November 2002	Generic	Maryland	Energy Administration Dept. Natural Resources	Standard Offer Service
245.	02S-315EG November 2002	Public Service Company of Colorado	Colorado	Fed. Executive Agencies	Rate of Return

246.	EL02-111-000 December 2002	PJM/MISO	FERC	MD PSC	Transmission Ratemaking
247.	02-0479 February 2003	Commonwealth Edison	Illinois	Dept. of Energy	POLR Service
248.	PL03-1-000 March 2003	Generic	FERC	NASUCA	Transmission Pricing (Affidavit)
249.	U-27136 April 2003	Entergy Louisiana	Louisiana	Staff	Purchase Power Contracts
250.	8908 Phase II July 2003	Generic	Maryland	Energy Administration Dept. of Natural Resources	Standard Offer Service
251.	U-27192 June 2003	Entergy Louisiana and Gulf States	Louisiana	LPSC Staff	Purchase Power Contract Cost Recovery
252.	C2-99-1181 October 2003	Ohio Edison Company	U.S. District Court	U.S. Department of Justice, et al.	Clean Air Act Compliance Economic Impact (Report)
253.	RP03-398-000 December 2003	Northern Natural Gas Co.	FERC	Municipal Distributors Group/Gas Task Force	Rate of Return
254.	8738 December 2003	Generic	Maryland	Energy Admin Department of Natural Resources	Environmental Disclosure (oral only)
255.	U-27136 December 2003	Entergy Louisiana, Inc.	Louisiana	PSC Staff	Purchase Power Contracts
256.	U-27192, Phase II October/December 2003	Entergy Louisiana & Entergy Gulf States	Louisiana	PSC Staff	Purchase Power Contracts
257.	WC Docket 03-173 December 2003	Generic	FCC	MCI	Cost of Capital (TELRIC)
258.	ER 030 20110 January 2004	Atlantic City Electric	New Jersey	Ratepayer Advocate	Rate of Return
259.	E-01345A-03-0437 January 2004	Arizona Public Service Company	Arizona	Federal Executive Agencies	Rate of Return
260.	03-10001 January 2004	Nevada Power Company	Nevada	U.S. Dept. of Energy	Rate of Return

261.	R-00049255 June 2004	PPL Elec. Utility	Pennsylvania	Office of Consumer Advocate	Rate of Return
262.	U-20925 July 2004	Entergy Louisiana, Inc.	Louisiana	PSC Staff	Rate of Return Capacity Resources
263.	U-27866 September 2004	Southwest Electric Power Co.	Louisiana	PSC Staff	Purchase Power Contract
264.	U-27980 September 2004	Cleco Power	Louisiana	PSC Staff	Purchase Power Contract
265.	U-27865 October 2004	Entergy Louisiana, Inc. Entergy Gulf States	Louisiana	PSC Staff	Purchase Power Contract
266.	RP04-155 December 2004	Northern Natural Gas Company	FERC	Municipal Distributors Group/Gas Task Force	Rate of Return
267.	U-27836 January 2005	Entergy Louisiana/ Gulf States	Louisiana	PSC Staff	Power plant Purchase and Cost Recovery
268.	U-199040 et al. February 2005	Entergy Gulf States/ Louisiana	Louisiana	PSC Staff	Global Settlement, Multiple rate proceedings
269.	EF03070532 March 2005	Public Service Electric & Gas	New Jersey	Ratepayers Advocate	Securitization of Deferred Costs
270.	05-0159 June 2005	Commonwealth Edison	Illinois	Department of Energy	POLR Service
271.	U-28804 June 2005	Entergy Louisiana	Louisiana	LPSC Staff	QF Contract
272.	U-28805 June 2005	Entergy Gulf States	Louisiana	LPSC Staff	QF Contract
273.	05-0045-EI June 2005	Florida Power & Lt.	Florida	Federal Executive Agencies	Rate of Return
274.	9037 July 2005	Generic	Maryland	MD. Energy Administration	POLR Service
275.	U-28155 August 2005	Entergy Louisiana Entergy Gulf States	Louisiana	LPSC Staff	Independent Coordinator of Transmission Plan

276.	U-27866-A September 2005	Southwestern Electric Power Company	Louisiana	LPSC Staff	Purchase Power Contract
277.	U-28765 October 2005	Cleco Power LLC	Louisiana	LPSC Staff	Purchase Power Contract
278.	U-27469 October 2005	Entergy Louisiana Entergy Gulf States	Louisiana	LPSC Staff	Avoided Cost Methodology
279.	A-313200F007 October 2005	Sprint (United of PA)	Pennsylvania	Office of Consumer Advocate	Corporate Restructuring
280.	EM05020106 November 2005	Public Service Electric & Gas Company	New Jersey	Ratepayer Advocate	Merger Issues
281.	U-28765 December 2005	Cleco Power LLC	Louisiana	LPSC Staff	Plant Certification, Financing, Rate Plan
282.	U-29157 February 2006	Cleco Power LLC	Louisiana	LPSC Staff	Storm Damage Financing
283.	U-29204 March 2006	Entergy Louisiana Entergy Gulf States	Louisiana	LPSC Staff	Purchase power contracts
284.	A-310325F006 March 2006	Alltel	Pennsylvania	Office of Consumer Advocate	Merger, Corporate Restructuring
285.	9056 March 2006	Generic	Maryland	Maryland Energy Administration	Standard Offer Service Structure
286.	C2-99-1182 April 2006	American Electric Power Utilities	U. S. District Court Southern District, Ohio	U. S. Department of Justice	New Source Review Enforcement (expert report)
287.	EM05121058 April 2006	Atlantic City Electric	New Jersey	Ratepayer Advocate	Power plant Sale
288.	ER05121018 June 2006	Jersey Central Power & Light Company	New Jersey	Ratepayer Advocate	NUG Contracts Cost Recovery
289.	U-21496, Subdocket C June 2006	Cleco Power LLC	Louisiana	Commission Staff	Rate Stabilization Plan
290.	GR0510085 June 2006	Public Service Electric & Gas Company	New Jersey	Ratepayer Advocate	Rate of Return (gas services)

291.	R-000061366 July 2006	Metropolitan Ed. Company Penn. Electric Company	Pennsylvania	Office of Consumer Advocate	Rate of Return
292.	9064 September 2006	Generic	Maryland	Energy Administration	Standard Offer Service
293.	U-29599 September 2006	Cleco Power LLC	Louisiana	Commission Staff	Purchase Power Contracts
294.	WR06030257 September 2006	New Jersey American Water Company	New Jersey	Rate Counsel	Rate of Return
295.	U-27866/U-29702 October 2006	Southwestern Electric Power Company	Louisiana	Commission Staff	Purchase Power/Power Plant Certification
296.	9063 October 2006	Generic	Maryland	Energy Administration Department of Natural Resources	Generation Supply Policies
297.	EM06090638 November 2006	Atlantic City Electric	New Jersey	Rate Counsel	Power Plant Sale
298.	C-2000065942 November 2006	Pike County Light & Power	Pennsylvania	Consumer Advocate	Generation Supply Service
299.	ER06060483 November 2006	Rockland Electric Company	New Jersey	Rate Counsel	Rate of Return
300.	A-110150F0035 December 2006	Duquesne Light Company	Pennsylvania	Consumer Advocate	Merger Issues
301.	U-29203, Phase II January 2007	Entergy Gulf States Entergy Louisiana	Louisiana	Commission Staff	Storm Damage Cost Allocation
302.	06-11022 February 2007	Nevada Power Company	Nevada	U.S. Dept. of Energy	Rate of Return
303.	U-29526 March 2007	Cleco Power	Louisiana	Commission Staff	Affiliate Transactions
304.	P-00072245 March 2007	Pike County Light & Power	Pennsylvania	Consumer Advocate	Provider of Last Resort Service
305.	P-00072247 March 2007	Duquesne Light Company	Pennsylvania	Consumer Advocate	Provider of Last Resort Service

306.	EM07010026 May 2007	Jersey Central Power & Light Company	New Jersey	Rate Counsel	Power Plant Sale
307.	U-30050 June 2007	Entergy Louisiana Entergy Gulf States	Louisiana	Commission Staff	Purchase Power Contract
308.	U-29956 June 2007	Entergy Louisiana	Louisiana	Commission Staff	Black Start Unit
309.	U-29702 June 2007	Southwestern Electric Power Company	Louisiana	Commission Staff	Power Plant Certification
310.	U-29955 July 2007	Entergy Louisiana Entergy Gulf States	Louisiana	Commission Staff	Purchase Power Contracts
311.	2007-67 July 2007	FairPoint Communications	Maine	Office of Public Advocate	Merger Financial Issues
312.	P-00072259 July 2007	Metropolitan Edison Co.	Pennsylvania	Office of Consumer Advocate	Purchase Power Contract Restructuring
313.	EO07040278 September 2007	Public Service Electric & Gas	New Jersey	Rate Counsel	Solar Energy Program Financial Issues
314.	U-30192 September 2007	Entergy Louisiana	Louisiana	Commission Staff	Power Plant Certification Ratemaking, Financing
315.	9117 (Phase II) October 2007	Generic (Electric)	Maryland	Energy Administration	Standard Offer Service Reliability
316.	U-30050 November 2007	Entergy Gulf States	Louisiana	Commission Staff	Power Plant Acquisition
317.	IPC-E-07-8 December 2007	Idaho Power Co.	Idaho	U.S. Department of Energy	Cost of Capital
318.	U-30422 (Phase I) January 2008	Entergy Gulf States	Louisiana	Commission Staff	Purchase Power Contract
319.	U-29702 (Phase II) February, 2008	Southwestern Electric Power Co.	Louisiana	Commission Staff	Power Plant Certification
320.	March 2008	Delmarva Power & Light	Delaware State Senate	Senate Committee	Wind Energy Economics
321.	U-30192 (Phase II) March 2008	Entergy Louisiana	Louisiana	Commission Staff	Cash CWIP Policy, Credit Ratings

322.	U-30422 (Phase II) April 2008	Entergy Gulf States - LA	Louisiana	Commission Staff	Power Plant Acquisition
323.	U-29955 (Phase II) April 2008	Entergy Gulf States - LA Entergy Louisiana	Louisiana	Commission Staff	Purchase Power Contract
324.	GR-070110889 April 2008	New Jersey Natural Gas Company	New Jersey	Rate Counsel	Cost of Capital
325.	WR-08010020 July 2008	New Jersey American Water Company	New Jersey	Rate Counsel	Cost of Capital
326.	U-28804-A August 2008	Entergy Louisiana	Louisiana	Commission Staff	Cogeneration Contract
327.	IP-99-1693C-M/S August 2008	Duke Energy Indiana	Federal District Court	U.S. Department of Justice/ Environmental Protection Agency	Clean Air Act Compliance (Expert Report)
328.	U-30670 September 2008	Entergy Louisiana	Louisiana	Commission Staff	Nuclear Plant Equipment Replacement
329.	9149 October 2008	Generic	Maryland	Department of Natural Resources	Capacity Adequacy/Reliability
330.	IPC-E-08-10 October 2008	Idaho Power Company	Idaho	U.S. Department of Energy	Cost of Capital
331.	U-30727 October 2008	Cleco Power LLC	Louisiana	Commission Staff	Purchased Power Contract
332.	U-30689-A December 2008	Cleco Power LLC	Louisiana	Commission Staff	Transmission Upgrade Project
333.	IP-99-1693C-M/S February 2009	Duke Energy Indiana	Federal District Court	U.S. Department of Justice/EPA	Clean Air Act Compliance (Oral Testimony)
334.	U-30192, Phase II February 2009	Entergy Louisiana, LLC	Louisiana	Commission Staff	CWIP Rate Request Plant Allocation
335.	U-28805-B February 2009	Entergy Gulf States, LLC	Louisiana	Commission Staff	Cogeneration Contract
336.	P-2009-2093055, et al. May 2009	Metropolitan Edison Pennsylvania Electric	Pennsylvania	Office of Consumer Advocate	Default Service
337.	U-30958 July 2009	Cleco Power	Louisiana	Commission Staff	Purchase Power Contract

338.	EO08050326 August 2009	Jersey Central Power Light Co.	New Jersey	Rate Counsel	Demand Response Cost Recovery
339.	GR09030195 August 2009	Elizabethtown Gas	New Jersey	New Jersey Rate Counsel	Cost of Capital
340.	U-30422-A August 2009	Entergy Gulf States	Louisiana	Staff	Generating Unit Purchase
341.	CV 1:99-01693 August 2009	Duke Energy Indiana	Federal District Court – Indiana	U. S. DOJ/EPA, et al.	Environmental Compliance Rate Impacts (Expert Report)
342.	4065 September 2009	Narragansett Electric	Rhode Island	Division Staff	Cost of Capital
343.	U-30689 September 2009	Cleco Power	Louisiana	Staff	Cost of Capital, Rate Design, Other Rate Case Issues
344.	U-31147 October 2009	Entergy Gulf States Entergy Louisiana	Louisiana	Staff	Purchase Power Contracts
345.	U-30913 November 2009	Cleco Power	Louisiana	Staff	Certification of Generating Unit
346.	M-2009-2123951 November 2009	West Penn Power	Pennsylvania	Office of Consumer Advocate	Smart Meter Cost of Capital (Surrebuttal Only)
347.	GR09050422 November 2009	Public Service Electric & Gas Company	New Jersey	Rate Counsel	Cost of Capital
348.	D-09-49 November 2009	Narragansett Electric	Rhode Island	Division Staff	Securities Issuances
349.	U-29702, Phase II November 2009	Southwestern Electric Power Company	Louisiana	Commission Staff	Cash CWIP Recovery
350.	U-30981 December 2009	Entergy Louisiana Entergy Gulf States	Louisiana	Commission Staff	Storm Damage Cost Allocation
351.	U-31196 (ITA Phase) February 2010	Entergy Louisiana	Louisiana	Staff	Purchase Power Contract
352.	ER09080668 March 2010	Rockland Electric	New Jersey	Rate Counsel	Rate of Return
353.	GR10010035 May 2010	South Jersey Gas Co.	New Jersey	Rate Counsel	Rate of Return

354.	P-2010-2157862 May 2010	Pennsylvania Power Co.	Pennsylvania	Consumer Advocate	Default Service Program
355.	10-CV-2275 June 2010	Xcel Energy	U.S. District Court Minnesota	U.S. Dept. Justice/EPA	Clean Air Act Enforcement
356.	WR09120987 June 2010	United Water New Jersey	New Jersey	Rate Counsel	Rate of Return
357.	U-30192, Phase III June 2010	Entergy Louisiana	Louisiana	Staff	Power Plant Cancellation Costs
358.	31299 July 2010	Cleco Power	Louisiana	Staff	Securities Issuances
359.	App. No. 1601162 July 2010	EPCOR Water	Alberta, Canada	Regional Customer Group	Cost of Capital
360.	U-31196 July 2010	Entergy Louisiana	Louisiana	Staff	Purchase Power Contract
361.	2:10-CV-13101 August 2010	Detroit Edison	U.S. District Court Eastern Michigan	U.S. Dept. of Justice/EPA	Clean Air Act Enforcement
362.	U-31196 August 2010	Entergy Louisiana Entergy Gulf States	Louisiana	Staff	Generating Unit Purchase and Cost Recovery
363.	Case No. 9233 October 2010	Potomac Edison Company	Maryland	Energy Administration	Merger Issues
364.	2010-2194652 November 2010	Pike County Light & Power	Pennsylvania	Consumer Advocate	Default Service Plan
365.	2010-2213369 April 2011	Duquesne Light Company	Pennsylvania	Consumer Advocate	Merger Issues
366.	U-31841 May 2011	Entergy Gulf States	Louisiana	Staff	Purchase Power Agreement
367.	11-06006 September 2011	Nevada Power	Nevada	U. S. Department of Energy	Cost of Capital
368.	9271 September 2011	Exelon/Constellation	Maryland	MD Energy Administration	Merger Savings
369.	4255 September 2011	United Water Rhode Island	Rhode Island	Division of Public Utilities	Rate of Return

370.	P-2011-2252042 October 2011	Pike County Light & Power	Pennsylvania	Consumer Advocate	Default service plan
371.	U-32095 November 2011	Southwestern Electric Power Company	Louisiana	Commission Staff	Wind energy contract
372.	U-32031 November 2011	Entergy Gulf States Louisiana	Louisiana	Commission Staff	Purchased Power Contract
373.	U-32088 January 2012	Entergy Louisiana	Louisiana	Commission Staff	Coal plant evaluation
374.	R-2011-2267958 February 2012	Aqua Pa.	Pennsylvania	Office of Consumer Advocate	Cost of capital
375.	P-2011-2273650 February 2012	FirstEnergy Companies	Pennsylvania	Office of Consumer Advocate	Default service plan
376.	U-32223 March 2012	Cleco Power	Louisiana	Commission Staff	Purchase Power Contract and Rate Recovery
377.	U-32148 March 2012	Entergy Louisiana Energy Gulf States	Louisiana	Commission Staff	RTO Membership
378.	ER11080469 April 2012	Atlantic City Electric	New Jersey	Rate Counsel	Cost of capital
379.	R-2012-2285985 May 2012	Peoples Natural Gas Company	Pennsylvania	Office of Consumer Advocate	Cost of capital
380.	U-32153 July 2012	Cleco Power	Louisiana	Commission Staff	Environmental Compliance Plan
381.	U-32435 August 2012	Entergy Gulf States Louisiana LLC	Louisiana	Commission Staff	Cost of equity (gas)
382.	ER-2012-0174 August 2012	Kansas City Power & Light Company	Missouri	U. S. Department of Energy	Rate of return
383.	U-31196 August 2012	Entergy Louisiana/ Entergy Gulf States	Louisiana	Commission Staff	Power Plant Joint Ownership
384.	ER-2012-0175 August 2012	KCP&L Greater Missouri Operations	Missouri	U.S. Department of Energy	Rate of Return
385.	4323 August 2012	Narragansett Electric Company	Rhode Island	Division of Public Utilities and Carriers	Rate of Return (electric and gas)

386.	D-12-049 October 2012	Narragansett Electric Company	Rhode Island	Division of Public Utilities and Carriers	Debt issue
387.	GO12070640 October 2012	New Jersey Natural Gas Company	New Jersey	Rate Counsel	Cost of capital
388.	GO12050363 November 2012	South Jersey Gas Company	New Jersey	Rate Counsel	Cost of capital
389.	R-2012-2321748 January 2013	Columbia Gas of Pennsylvania	Pennsylvania	Office of Consumer Advocate	Cost of capital
390.	U-32220 February 2013	Southwestern Electric Power Co.	Louisiana	Commission Staff	Formula Rate Plan
391.	CV No. 12-1286 February 2013	PPL et al.	Federal District Court	MD Public Service Commission	PJM Market Impacts (deposition)
392.	EL13-48-000 February 2013	BGE, PHI subsidiaries	FERC	Joint Customer Group	Transmission Cost of Equity
393.	EO12080721 March 2013	Public Service Electric & Gas	New Jersey	Rate Counsel	Solar Tracker ROE
394.	EO12080726 March 2013	Public Service Electric & Gas	New Jersey	Rate Counsel	Solar Tracker ROE
395.	CV12-1286MJG March 2013	PPL, PSEG	U.S. District Court for the District of Md.	Md. Public Service Commission	Capacity Market Issues (trial testimony)
396.	U-32628 April 2013	Entergy Louisiana and Gulf States Louisiana	Louisiana	Staff	Avoided cost methodology
397.	U-32675 June 2013	Entergy Louisiana and Entergy Gulf States	Louisiana	Staff	RTO Integration Issues
398.	ER12111052 June 2013	Jersey Central Power & Light Company	New Jersey	Rate Counsel	Cost of capital
399.	PUE-2013-00020 July 2013	Dominion Virginia Power	Virginia	Apartment & Office Building Assoc. of Met. Washington	Cost of capital
400.	U-32766 August 2013	Cleco Power	Louisiana	Staff	Power plant acquisition
401.	U-32764 September 2013	Entergy Louisiana and Entergy Gulf States	Louisiana	Staff	Storm Damage Cost Allocation

402.	P-2013-237-1666 September 2013	Pike County Light and Power Co.	Pennsylvania	Office of Consumer Advocate	Default Generation Service
403.	E013020155 and G013020156 October 2013	Public Service Electric and Gas Company	New Jersey	Rate Counsel	Cost of capital
404.	U-32507 November 2013	Cleco Power	Louisiana	Staff	Environmental Compliance Plan
405.	DE11-250 December 2013	Public Service Co. New Hampshire	New Hampshire	Consumer Advocate	Power plant investment prudence
406.	4434 February 2014	United Water Rhode Island	Rhode Island	Staff	Cost of Capital
407.	U-32987 February 2014	Atmos Energy	Louisiana	Staff	Cost of Capital
408.	EL 14-28-000 February 2014	Entergy Louisiana Entergy Gulf States	FERC	LPSC	Avoided Cost Methodology (affidavit)

APPENDIX C

PAST TESTIMONY ON DEFAULT GENERATION SERVICE OF

MATTHEW I. KAHAL

Expert Testimony
of Matthew I. Kahal

	Docket Number	Utility	Jurisdiction	Client
236.	P-00011872 May 2002	Pike County Power & Light	Pennsylvania	Consumer Advocate
242.	8936 October 2002	Delmarva Power & Light	Maryland	Energy Administration Dept. Natural Resources
244.	8908 Phase I November 2002	Generic	Maryland	Energy Administration Dept. Natural Resources
247.	02-0479 February 2003	Commonwealth Edison	Illinois	Dept. of Energy
250.	8908 Phase II July 2003	Generic	Maryland	Energy Administration Dept. of Natural Resources
270.	05-0159 June 2005	Commonwealth Edison	Illinois	Department of Energy
274.	9037 July 2005	Generic	Maryland	MD. Energy Administration
285.	9056 March 2006	Generic	Maryland	Maryland Energy Administration
292.	9064 September 2006	Generic	Maryland	Energy Administration
304.	P-00072245 March 2007	Pike County Light & Power	Pennsylvania	Consumer Advocate
305.	P-00072247 March 2007	Duquesne Light Company	Pennsylvania	Consumer Advocate
315.	9117 (Phase II) October 2007	Generic (Electric)	Maryland	Energy Administration
336.	P-2009-2093055, et al. May 2009	Metropolitan Edison Pennsylvania Electric	Pennsylvania	Office of Consumer Advocate
354.	P-2010-2157862 May 2010	Pennsylvania Power Co.	Pennsylvania	Consumer Advocate
364.	2010-2194652 November 2010	Pike County Light & Power	Pennsylvania	Consumer Advocate
370.	P-2011-2252042 October 2011	Pike County Light & Power	Pennsylvania	Consumer Advocate
375.	P-2011-2273650 February 2012	FirstEnergy Companies	Pennsylvania	Office of Consumer Advocate
402.	P-2013-237-1666 September 2013	Pike County Light and Power Co.	Pennsylvania	Office of Consumer Advocate