STATE OF MARYLAND

BEFORE THE PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE	**)**	
APPLICATION OF POTOMAC	**)**	**Case No. 9418**
ELECTRIC POWER COMPANY	**)**	
FOR ADJUSTMENTS TO ITS	**)**	
RETAIL RATES FOR THE		
DISTRIBUTION OF ELECTRIC		
ENERGY		

DIRECT TESTIMONY OF

PAUL CHERNICK

ON BEHALF OF

THE OFFICE OF PEOPLES COUNSEL

Resource Insight, Inc.

JULY 6, 2016

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I. Identification & Qualifications

Q: Mr. Chernick, please state your name, occupation, and business address.

A: I am Paul L. Chernick. I am the president of Resource Insight, Inc., 5 Water St., Arlington, Massachusetts.

Q: Summarize your professional education and experience.

A: I received an SB degree from the Massachusetts Institute of Technology in June 1974 from the Civil Engineering Department, and an SM degree from the Massachusetts Institute of Technology in February 1978 in technology and policy. I have been elected to membership in the civil-engineering honorary society Chi Epsilon, and the engineering honor society Tau Beta Pi, and to associate membership in the research honorary society Sigma Xi.

I was a utility analyst for the Massachusetts Attorney General for more than three years, and was involved in numerous aspects of utility rate design, costing, load forecasting, and the evaluation of power supply options. Since 1981, I have been a consultant in utility regulation and planning, first as a research associate at Analysis and Inference, after 1986 as president of PLC, Inc., and in my current position at Resource Insight. In these capacities, I have advised a variety of clients on utility matters.

My work has considered, among other things, the cost-effectiveness of prospective new electric generation plants and transmission lines, retrospective review of generation-planning decisions, ratemaking for plant under construction, ratemaking for excess and/or uneconomical plant entering service, conservation program design, cost recovery for utility efficiency programs, the valuation of environmental externalities from energy production and use, allocation of costs of service between rate classes and jurisdictions, design of retail and wholesale rates, and performance-based ratemaking and cost recovery in restructured gas and electric industries. My professional qualifications are further summarized in Exhibit PLC-1.

Q: Have you testified previously in utility proceedings?

A: Yes. I have testified over three hundred times on utility issues before various regulatory, legislative, and judicial bodies, including utility regulators in thirty-four states and six Canadian provinces, and two US Federal agencies. This testimony has included many reviews of utility avoided costs, marginal costs, rate design, and related issues.

Q: Have you testified previously before the Commission?

A: Yes. I have testified approximately 17 times before the Commission, from 1990 through 2015, as follows:

- Case No. 8278, on the adequacy of the integrated resource plan of Baltimore Gas & Electric (BGE);
- Case No. 8241, Phase II of BGE's Application for CPCN for the Perryman Project;
- Case No. 8473, Review of the Power Sales Agreement of BGE with AES Northside;
- Case No. 8487, BGE 1993 Electric Rate Case, on cost allocation and rate design;
- Case No. 8179, Approval of Amendment No. 2 to Potomac Edison Purchase Agreement with AES Warrior Run;
- Case No. 8697, BGE 1995 gas rate proceeding, on cost allocation and rate design;
- Case No. 8720, Washington Gas Light (WGL), on DSM avoided costs and least-cost planning;

- Case No. 8725, the proposed merger of BGE and Potomac Electric Power Company (Pepco), on allocation of merger benefits and rate reductions;
- Case No. 8774, the proposed Allegheny Power-Duquesne merger;
- Case Nos. 8794 and 8804, BGE restructuring;
- Case No. 8795, Delmarva Power & Light (DPL) restructuring;
- Case No. 8797, Potomac Edison restructuring;
- Case No. 9036, BGE's 2005 rate proceeding;
- Case No. 9159, Columbia Gas's 2009 rate proceeding; and
- Case No. 9230, BGE's 2010 rate proceeding.
- Case No. 9361, the proposed merger of Exelon and Pepco Holdings.
- Case Nos. 9153, et al., the 2015 review of the EmPOWER Maryland programs.
- Case No. 9406, on the benefits of the BGE smart-grid programs.

I testified on behalf of the OPC in each of these proceedings, other than Case No. 9361, in which I testified on behalf of the Sierra Club and Chesapeake Climate Action Network.

II. Introduction

Q: On whose behalf are you testifying?

A: I am testifying on behalf of the Maryland Office of Peoples Counsel.

Q: What is the scope of your testimony?

A: I review some of the benefits that Pepco asserts are provided by residential programs supported by the advanced meters of Pepco's recent advanced-metering infrastructure (AMI) investment:

- The Dynamic Pricing (DP) demand-response program, which provides a Peak Energy Savings Credit (PESC) to customers who reduce usage on designated hours on Energy Savings Days (ESDs).
- The Energy Manager Tools (EMT) energy-efficiency program.
- Conservation Voltage Reduction (CVR) enhancements from AMI data.
- Incremental savings from the pre-existing Energy Wise Rewards (EWR) residential air conditioner cycling direct load-control program.[1]

Q: What aspects of Pepco's benefit estimates do you review?

A: My review focuses primarily on the following five categories of annual program savings, in terms of the value of reductions in \$/kWh and \$/MW-day:[2]

Table 1: Pepco claimed AMI Benefit Categories

Type	Driver	Programs	Pepco ID
Pepco revenues	Energy sales to PJM	DP	OPR 19
	Cleared PJM Capacity	DP, EWR	OPR 18
Avoided costs from load reductions	Energy consumption	DP, CVR, EMT	DSM 04, 09, 14
	Capacity obligation	All	DSM 03, 08, 13
Price mitigation by added supply & reduced demand	Energy price	DP, CVR, EMT	DSM 02, 07, 12
	Capacity price		DSM 01, 06, 11
Transmission investment	Load reductions	DP, CVR, EMT	OPR 20, 22, 24
Distribution investment	Load reductions		OPR 21, 23, 25

In Pepco's terminology, the benefits related to the generation market are demand-side (DSM) benefits, while the T&D savings are a portion of the operational (OPR) benefits (which also include various operating costs). I will

[1] In many places in its filing and discovery responses, Pepco includes the EWR savings and benefit as part of the DP program.

[2] Pepco also includes about \$2 million in avoided environmental costs, based on the \$2/MWh value estimated by Itron (Giovannini Direct at 17). This value is too small to warrant much attention, other than reducing the environmental benefits in proportion to any adjustments to the estimate of program energy savings.

refer to all the generation-market benefits and the avoided T&D as program benefits, since Pepco attributes all those benefits to the operation of its programs.

The system benefits claimed by Pepco are described at a high level of generality in the testimony of Pepco witnesses Karen Lefkowitz and Mario Giovannini, and documented primarily in the spreadsheets provided as attachments to Staff DR 6-01, particularly Attachment C.[3]

In Exhibit PLC-2, I attach the non-confidential data requests that I cite, excluding only the bulky spreadsheets, such as Attachment 15 to Staff DR 6-02.

I am aware of the Commission's recent decision in Case No. 9406 on BGE's AMI investment; I understand that matter to be subject to additional proceedings. I have analyzed the benefits of Pepco's AMI programs on their own merits, without reference to Case No. 9406.

Q: Did you review any other matters?

A: In addition to reviewing and as appropriate re-estimating these unit-price values per kilowatt-hour and per megawatt-day, I reviewed some related issues, such as the extent to which the types of peak reduction achieved by the various programs would affect the capacity costs borne by Pepco ratepayers and other Maryland ratepayers. I also offer some comments on the treatment of the payments to PESC participants and the magnitude of PESC savings.

Q: What do you mean by "types of peak reduction"?

A: The term "peak" has a range of meanings, in a variety of applications. "Peak load" may refer to PJM's maximum load on a single annual hour, on several monthly maximum hours, or many high-load hours. Other types of peak may be defined as

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[3] For brevity, I refer to this spreadsheet as "Attachment C." Pepco provided an update Attachment C on July 1, which I have not yet reviewed. I will revise this testimony to reflect any important changes in that update.

the maximum load (or a number of high loads) for Pepco, SWMAAC, MAAC, a particular Pepco rate class, a transmission line, a substation, or a feeder. Each demand-related cost category is driven by its own type of peak, which may be different from the type of peak driving other costs.

Q: Are the categories of program benefits that Pepco claims from the AMI programs all costs that can be avoided by some types of load reductions?

A: Yes. These categories of benefits are real. The questions I address are whether Pepco has properly estimated the benefits, including whether the nature of the programs will provide those benefits.

Q: Will you present conclusions about the cost-effectiveness of Pepco's smart-grid investment?

A: No. The testimony of Max Chang, on behalf of OPC, combines my unit-price results and other results with corrected estimates of program energy and capacity savings, and of operational benefits, to determine the overall cost-effectiveness of the investment.

Q: How important are the various portions of the benefits that you review?

A: Table 2 disaggregates the program benefits among the three programs and the various components that Pepco includes, based on Ms. Lefkowitz's Table F, Mr. Giovannini's Table 1, and Staff DR 6-1 Attachment C.

Table 2: Breakdown of Pepco Claimed System Benefits, $M in 2015 PV

Benefit Category	CVR	DP & EWR	EMT	Total
Capacity Price Mitigation	$4.6	$150.6	$9.2	$164.5
Energy Price Mitigation	$0.7	$0.0	$0.5	$1.2
Capacity Revenue	—	$35.2	—	$35.2
Energy Revenue	—	$0.1	—	$0.1
Avoided Capacity	$3.6	—	$8.6	$38.8
Avoided Energy	$47.8	$1.4	$57.1	$106.2
Reduction in Air Emissions	$1.5	$0.0	$1.8	$3.4
Avoided Transmission Capital Recovery	$7.1	$65.9	$13.9	$87.0
Avoided Distribution Capital Recovery	$3.1	$29.0	$6.1	$38.2
Total	$68.5	$308.8	$97.3	$474.6

The claimed benefits are dominated by the capacity benefits of the DP program (65% of the total).

Q: Please summarize your conclusions.

A: The benefits claimed by Pepco are overstated due to over a dozen distinct errors (in addition to any overstatement of savings discussed in the testimony of OPC witness Max Chang), the most important of which are as follows:

- The DP and EWR load reductions, given their rarity and timing, are unlikely to affect transmission or distribution investment.
- For similar reasons, the capacity obligation for Pepco customers and capacity price for all Maryland customers will not be significantly reduced by the DP and EWR load reductions.
- Reductions in contribution to PJM peak load have less effect on capacity prices than Pepco assumes.
- Pepco's estimate of energy price mitigation is significantly overstated, because Pepco has incorrectly assumed that energy prices for each of the Maryland zones is driven by Maryland load. In reality, the Pepco energy price is driven by loads over a large area (probably most of PJM, and possibly adjacent regions), as are the energy prices for BGE, Delmarva and

Potomac Edison. A 1% change in Pepco load appears to reduce energy prices by less than half of Pepco's estimate.

All of these errors and the lower-impact errors are discussed in Sections III through VIII and summarized in Section IX.

III. Treatment of the Dynamic-Pricing Rebate

Q: How should the Commission treat the rebates in the DP program?

A: The rebates represent how much participants insist on being paid in exchange for bearing the burden of the program and should thus be treated as a cost. The DP program pays $1.25/kWh customers to suffer discomfort and inconvenience, to tolerate higher indoor temperature and humidity on the most unpleasant summer days, and to rearrange their household schedules.

Q: How does Pepco treat the rebates?

A: Mr. Giovannini says that "The costs of customer bill credits or 'rebates' are treated as a transfer payment in the Company's AMI cost-effectiveness analysis." (OPC DR 8-10).

Q: What is a "transfer payment"?

A: A typical definition of a transfer payment in economics would be "A payment that does not form part of an exchange of services but rather represents a gift without anything being received or required in return" or "One-way payment for which no money, good, or service is received in exchange."

Q: How is the concept of a transfer payment relevant to evaluating the cost-effectiveness of DSM programs?

A: This concept arises in the discussion of two aspects of valuation of energy-efficiency programs. First, reduced recovery of fixed costs from participants in any particular program shifts cost recovery to other customers in the same class and/or other classes. These shifts are treated as transfers among customers and are excluded from the TRC tests.

Second, the incentives paid by the utility to the participants, vendors, and other trade allies are treated as part of the program costs. The total cost of the measure is included in the TRC, regardless of the share of the costs absorbed by the participants, paid by participants and reimbursed by the utility, or paid directly by the utility. Payments by the utility to vendors, and other trade allies are normally part of measure costs, as is the total cost paid by participants, regardless of whether they are reimbursed by the utility.

Q: How do these concepts apply to the DP program?

A: The first concept—that shifts in fixed-cost recovery do not affect cost-effectiveness—means that the reduction in normal residential rates recovered from some customers is not treated as a cost or benefit. The second concept—that all costs of the program to participants or Pepco are included as costs in the TRC—means that all the costs borne by the participants must be treated as costs.

Q: What are the costs of the DP program to participants?

A: There are two categories of such costs: cash costs and the costs of lost service quality, discomfort and inconvenience.

The cash category includes purchasing internet-based remote controls or timers to change thermostat settings and turn off appliances in the PESC hours; buying take-out food to avoid cooking and reduce air-conditioning load from 1 PM to 7 PM; or using the gas oven rather than the microwave. The service-degradation costs include running around unplugging appliances at 1:30 and plugging them back in (and resetting all the clocks) at 6 PM; turning the thermostat up to 80° on a humid summer day; running laundry and washing dishes before 2 PM or after 6

PM; putting off showers and children's baths until after 6 PM; and resetting and rescheduling other appliances.

If Pepco could determine the dollar value of these costs of the DP program, the TRC test for the DP program would be straightforward. Unfortunately, Pepco does not know what customers are doing to shift energy usage out of the PESC hours, how much cash they are spending, or how much they value the disruption and discomfort of changing schedules and higher temperatures. So the cost of the DP measures must be estimated.

Q: Do other regulators include as TRC costs the payments to customers to reduce loads in demand-response programs?

A: Yes. A review of cost-effectiveness testing for demand-response programs for the Pennsylvania Public Utility Commission found that:

> there is consistency between states with published TRC test methods in regard to the treatment of DR program incentive payments. In California, New York and Pennsylvania, incentive payments made by EDCs to program participants are included in the TRC test as a proxy for participant costs. The rationale is that a participant's actual transaction costs cannot be readily or easily determined, but an end-user would not participate unless the incentives received are at least equal to the participant's costs to curtail usage during peak demand periods.[4]

The study also found that Illinois treats incentive payments as a cost, but not explicitly as a proxy for participant costs. The Pennsylvania PUC affirmed its treatment of incentive costs in Case M-2015-2468992, June 11, 2015.

Q: Do energy-efficiency programs have participant costs similar to those in the DP program?

[4] Gogte, S, et al.; Act 129 Demand Response Study, Final Report; GDS Associates, Nexant, and Mondre Energy; May 13, 2013, at .

A: No. Energy-efficiency programs are designed to reduce the barriers to adoption of efficient technologies that provide the participant with equal or higher service quality than the existing or standard technology. The program design strives to align the incentives of trade allies (retailers, wholesales, contractors, builders, plumbers) with customer interests, to reduce first-cost barriers (and hence programs with financing, decision-making and regret) and hassle (such as selecting contractors, and reviewing savings claims). Energy-efficiency programs do not need to pay customers for discomfort and inconvenience.

In terms of direct expenditures, energy-efficiency programs generally offset or reduce the costs of identifiable measures, explicitly identified in the cost-benefit analysis. In contrast, the DP program pays customers for unidentified expenses.

IV. Load Forecasts

Q: Which of Pepco's claimed benefits are affected by the forecast of loads for Pepco and other Maryland utilities?

A: Pepco includes load growth in the estimates of MW and GWh savings from the EMT, CVR, and DP programs.

Q: How do the current PJM load forecasts differ from those used in BGE's analysis?

A: As shown in Table 3, the PJM peak load forecast for Pepco is now 2–3% lower than the forecast that Pepco used in its benefits analysis. The PJM forecast for Pepco energy use is slightly higher in 2016 than in 2015.

Table 3: Updated of Forecast of Pepco Loads

	Summer peak				Energy			
	2015	2016	2016 ÷ 2015	2016 growth	2015	2016	2016 ÷ 2015	2016 growth
2015	6,640				31,066			
2016	6,694	6,563	98.0%	-1.2%	31,508	32,057	101.7%	3.2%
2017	6,728	6,614	98.3%	0.8%	31,708	32,242	101.7%	0.6%
2018	6,752	6,630	98.2%	0.2%	31,950	32,501	101.7%	0.8%
2019	6,795	6,669	98.1%	0.6%	32,134	32,644	101.6%	0.4%
2020	6,853	6,702	97.8%	0.5%	32,430	32,759	101.0%	0.4%
2021	6,881	6,672	97.0%	-0.4%	32,570	32,751	100.6%	0.0%
2022	6,920	6,680	96.5%	0.1%	32,796	32,879	100.3%	0.4%
2023	6,941	6,693	96.4%	0.2%	32,999	33,016	100.1%	0.4%

V. Pepco's Estimates of Load Reductions

Q: What types of load reductions does Pepco claim for its programs?

A: For the CVR and EMT programs, Pepco claims equal percentage load reductions in all hours. For DP and EWR, Pepco encourages or implements load reductions in a small number of hours—for DP, typically four contiguous hours on up to four summer days per year.

Q: Do these programs reduce demand at most of the hours that determine the total PJM capacity obligation and the portion of the capacity obligation that PJM allocates to the Pepco zone?

A: No. Each year, some 120 daily summer peaks contribute to the summer peak-load forecasts. The DP and EWR programs reduce loads on only a few days in each summer. Pepco called Energy Savings Days on two days in 2013, three days in 2014 and four in 2015. Table 4 lists the Energy Saving Days that Pepco selected in 2013, 2014, and 2015. (OPC DR 8-27)

Table 4: PESC Energy Saving Days

8/21/2013
9/11/2013
6/18/2014
8/27/2014
9/2/2014
7/21/2015
7/30/2015
8/3/2015
9/9/2015

Q: How did Pepco estimate the load reductions due to the DP program?

A: In its analysis for Pepco, Brattle defined DP savings by inventing the concept of an "engaged participant" which Brattle defines as a customer "who received a positive rebate on a given event day, using Pepco's Customer Baseline (CBL) Approach." (OPC DR 3-8 Attachment B, p. 3) Brattle estimated the DP savings as the sum of the its estimate of the reductions over all of the so-called participants, completely excluding the customers who increased usage.[5] Brattle then estimated the peak reduction each year as the average of the load reductions at hour-ending 17 (5 PM), adjusted to a weighted temperature-humidity index (WTHI) of 83.7°. There are at least four problems with this approach:

- Pepco counts all below-average loads on PESC days, but ignores the large number of customers with above-average loads.
- Pepco assumes that load reductions on a handful of summer days will reduce capacity obligations and prices.
- Pepco's peak-load analysis assumes that only the load reduction at hour 17 matters.
- The peak-load analysis assumes that capacity benefit will be determined by how much the load would have been reduced at 83.7° WTHI.

[5] Brattle conducted a regression analysis for each study year (2013 and 2014), to estimate customer normal usage in the event days, given usage on other days and the weather.

I discuss the first problem in the next section and the next three in Section B.

A. Including All Customers in the Dynamic Pricing Computation

Q: What problems did Pepco introduce in its selection of customers for its estimates of peak reductions from the DP program?

A: Pepco biases the analysis of DP saving and overstates the load reductions by including only a subset of customers.

Q: How did Pepco overestimate the load reductions due to the DP program?

A: In its analysis for Pepco, Brattle defined DP savings by inventing the concept of an "engaged participant" which Brattle defines as a customer "who received a positive rebate on a given event day, using Pepco's Customer Baseline (CBL) Approach." (OPC DR 3-8 Attachment B, p. 3) Brattle estimated the DP savings as the sum of the its estimate of the reductions over all of the so-called participants, completely excluding the customers who increased usage compared to the Pepco baseline and received no rebate.[6] As a result, Pepco's estimate of the DP savings includes reductions due to customers actually reacting to the $1.25/kWh incentive and also customers who just happened to have lower consumption that day for other reasons, but does not net out the customers who just happened to have higher consumption.[7]

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[6] Brattle conducted a regression analysis for each year, to estimate normal customer usage in the event days, given usage on other days and the weather. Hence, the Brattle study may have found that some of the rebated customers did not save any energy, while other customers saved more than Pepco credited them. But Brattle was working only with the biased group of rebated customers.

[7] The latter group might be called "free riders," since they get benefits from the program without actually responding to the program. The DP free riders do not intentionally shift loads; in energy-efficiency programs, free riders are participants who intentionally install efficiency measures, and thus provide benefits, but would have done so without the program incentives. Ms. Lefkowitz claims

Q: Why is this a problem?

A: There is no evidence that the "engaged" customers were all engaged, or that the reduction in load from the baseline days to the PESC day was all due to the DP program. All customers were automatically enrolled in the DP program, and various responded to the existence of the program in different ways, including the following:

- Some of them intended to decrease usage in the PESC hours, experienced no complications, and succeeded, resulting in benefits below the baseline.
- Others probably intended to decrease usage in the PESC hours, but experienced usage above the baseline.
- Other customers did not intend to decrease usage in the PESC hours, and had usage similar to the baseline.
- Others did not intend to decrease usage in the PESC hours, but reduced load for other reasons and had usage below the baseline.

All customers were subject to the same incentives, and the relevant measure of savings is the average or total response of all eligible customers.

Q: What factors might cause usage to vary from the baseline to the event day?

A: Aside from weather and reaction to the DP incentive, the usage of any one customer may be lower on the event day than would otherwise be expected (based on either the limited baseline used to assign rebates or the Brattle regression), including:

- The people who would normally be home during the day in the summer (e.g., children, supervising parents, at-home workers, retirees) being out of town on the event day.

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that the Brattle "panel regressions" somehow correct for free riders, but those regressions cannot identify the customers who received rebates without intending to respond to the PESC.

- The people who would normally be home during the day in the summer being out shopping, at the movies, etc., in the incentive hours.
- Shift workers (e.g., medical staff, retail clerks) who happen to be working the afternoon shift on the event day.
- An air conditioner or other appliance failing, decreasing load.

Similar events can operate in the opposite direction, increasing load on the PESC day: customers who are usually out of the house may be home on the PESC day or host a party, or equipment may operate in a way that increases load.

Q: Would Pepco's trick of counting only the customers who reduced use, and not those that increased use, be tolerated in reporting of results in other applications?

A: No. Imagine a drug company that told the FDA that a medication shortened malaria patients' hospital stays by an average of two days, but computed that statistic only for the half of "engaged" patients whose temperatures declined after treatment, ignoring the other half whose temperatures stayed constant or rose. Or a casino that claimed that it made its players $100 million richer, counting only the "engaged" winners and ignoring the losses by the many players who won nothing. Regulators would not tolerate those misrepresentations, and neither should the Commission.

Q: Does Pepco accept the reality that some of the customers who receive DP rebates were not responding to the program?

A: Yes. Pepco explains that:

> it is difficult to determine free ridership rates for this Program. For example, customers may have taken actions that include scheduling a vacation out of town during a typical week when temperature conditions are high and their energy use would have been high—this decision reduces regional electric loads and provides benefits. Similarly, if a customer was on vacation out of town prior to an event, it is likely that they would become "under paid riders" for the PESC Program. (OPC DR 12-4a)

While Pepco suggests that the inclusion of illusionary load reduction from the free riders may be symmetrical with the exclusion of load increase from the under-paid riders, the Pepco analysis breaks that symmetry. Pepco would include the effect of the first household being on vacation as a benefit of the DP program, but would leave the second household out of the analysis if the vacation took up most of the thirty days before the PESC day, resulting in its load increased from the baseline period (the customer's highest three usage days in the past thirty) to the PESC day. The Brattle analysis would not correct the inclusion of the first household. If the second household managed to show any load reduction on the PESC day, the Brattle analysis would compare its usage on the PESC to weather-adjusted usage over the entire summer, probably increasing the estimated savings on the PESC day above the rebated level.

Q: Does Pepco estimate the relative magnitude of over-estimates and under-estimates of DP load reductions?

A: Yes. Pepco states that:

> For any given PESC event there will be both free riders and "under paid riders". The quantity of each is largely related to the weather and resulting load conditions on the event day versus the weather and resulting load conditions on the days selected for a comparison event. Event days are more likely to have higher temperature conditions than non-event days over time and therefore the quantity of free riders may be exceeded by the quantity of under paid riders. (OPC DR 12-4d)

Q: Is Pepco correct in its conclusion that customers with overstated savings may be exceeded by those with understated savings?

A: No, for two reasons. First, the number of free riders and under-rebated customers is determined by much more than weather. As Pepco notes, if the household happened to be on vacation on the PESC day, it would almost certainly be counted as engaged, receive a rebate, and contribute to Pepco's claimed DP load reductions. If the household happened to be on vacation for a part of the preceding thirty days, it may still have three days that average out to usage higher than its PESC usage and receive a rebate.[8]

Second, Pepco excluded most of the "under-paid riders," since they would not have received a rebate and been labeled as "engaged." For the understated savings that achieved even a small reduction from the baseline to the PESC day, the Brattle analysis would have weather-adjusted the analysis based on the entire summer (diluting the effect of the vacation during the baseline and eliminating the effect of weather differences) and thus typically increased their estimated savings for the purpose of the AMI cost-benefit analysis.

Q: Can random variability contribute significantly to overstating the apparent savings from the DP program?

A: Yes. In OPC DR 8-29 Attachments A and B, Pepco provides data on the load increases on the PESC days by EWR customers whose load did not decrease. Most of those customers probably experienced failure of the Pepco-installed remote controls that would normally have cycled the air conditioner. Some of them may have increased their usage despite proper operation of the controls, because the customer overrode the control and/or the customer increased load in other ways.

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[8] One of those high-use days might have been the day that the household returned from vacation, turning on the air conditioning in a hot and stuffy home and doing the laundry that accumulated on vacation.

The values in OPC DR 8-29 appear to represent the difference between the customer's usage in the PESC hours compared to the customer's usage in the same hours in the baseline days.[9] While Pepco estimates that the average rebate recipient reduced usage by 1.4–3.0 kWh on the PESC days, the data in OPC DR 8-29 indicates those customers who did not receive rebates (and hence were not counted as "engaged" or as "participants") in 2013 and 2014 *increased* usage by an average of 1.8 to 3.0 kWh, depending on the day.[10] I assume that these customers did not intentionally increase their usage to avoid getting a rebate; the increases appear to result from random variability. That variability would result in similar random decreases in usage by the customers who received rebates.

Table 5 shows my computation of the average change in usage by all DP customers, assuming that the random increases among non-EWR customers are the same as among EWR customers.[11]

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[9] This is most clearly shown in OPC DR 8-29, Attachment C, which shows the baseline and PESC usage, as well as the difference.

[10] The average load increase for this category of customers in 2015 was 1.9 kWh (OPC DR 8-29, Attachment C); a very large number of non-rebated customers are reported, all for the same date, which appears to be July 30.

[11] Pepco has provided much less information for the 2015 PESC days, so I have not been able to do a similar computation for 2015.

Table 5: Offset to DP Savings by Customers Who Increased kWh Usage

Date	Δ kWh per rebated customer	% of customers rebated	Δ kWh per non-rebated customer	Δ kWh per average customer	Corrected Savings as % Pepco Estimate
8/21/2013	-1.57	79.5%	1.84	-0.87	70%
9/11/2013	-3.02	53.8%	2.24	-0.59	36%
6/18/2014	-2.28	45.4%	3.00	0.60	-58%
8/27/2014	-1.44	75.7%	1.77	-0.66	60%
9/2/2014	-2.53	57.7%	2.44	-0.43	29%
Average	-2.17			-0.39	28%

Sources: OPC DR 3-8 Attachments A and B,
OPC DR 8-29 Attachments A and B.

It thus appears that the random increases offset 30% to more than 100% of Pepco's claimed DP load reductions. Assuming that the random load declines that Pepco includes in its claimed savings are symmetrical with the random increases that it excludes, the actual savings due to the program would be about 28% of Pepco's estimate.

I have requested more comprehensive data from Pepco, but have not yet received and analyzed it. I will update the analysis as data become available.[12]

B. *Effect of Load Reductions on Capacity Responsibility*

Q: How long does Pepco assume it takes for a reduction in peak retail load to affect the capacity obligation for customers in the Pepco zone?

A: For the DP program, Pepco assumes zero or negative delay, so a megawatt load reduction in the summer of 2020 reduces the capacity obligation by 1 MW starting June 1, 2020, before the load reduction occurs. Pepco assumed that the reduction in load obligation would be the average of actual DP load reduction in the hour ending at 5 PM (hour 17) in the two to four ESDs each year (with four ESDs from

[12] Interestingly, Pepco has not asked PJM to perform similar modeling of the effects of load reductions on the load forecasts that determine Pepco capacity obligation and PJM's resource requirement (and hence, capacity prices). (OPC DR 8-19)

2016 on). For the other three programs, Pepco assumes a four-year delay, so a megawatt load reduction in 2014 reduces the capacity obligation starting June 2018.

Q: How are the capacity obligations of PJM zones determined?

A: For clarity, I will describe the process in terms of a particular capacity delivery year, starting in June of 2019. The PJM Resource Adequacy Planning Department conducts a series of regression analyses, for each load zone, in which the dependent variable is the daily peak load for the load zone, or its load coincident with the RTO load, or for other intermediate delivery areas, such as MAAC (the mid-Atlantic region, or roughly the pre-2002 PJM territory). The independent variables in the regressions are:

- various binary (or dummy) variables for the month, day of the week, and holidays, and
- various combinations of weather measures (e.g., cooling degree days and a temperature-humidity index or THI), an economic index, and equipment efficiency measures, with many variables being the product of two or more of these parameters (e.g., CDD × economy × cooling efficiency). The effect of THI (either by itself or times the cooling-efficiency index) is split into four ranges (or splines), which for Pepco are up to 65°, 65°–74°, 74°–83°, and over 83°.

The daily data cover the period from 1998 through the summer four years before the start of the delivery year, or August 2015 in our example. Those 6,400 observations are used to develop a regression equation for predicting (among other loads):

- PJM daily peak hour for various dates and weather conditions, given projected economic and efficiency trends.

- Pepco load in the PJM daily peak hour.

For the 2016 Load Forecast Report, PJM computed the RTO daily maximum loads for 273 variations of historical weather patterns, and identifies the peak load for each variant, and identifies the median peak for the delivery year (e.g., the summer of 2019). The forecast is used to determine the required reserve margin, and hence the total capacity obligation. The Pepco zonal capacity obligation is determined by the forecast of its contribution to the PJM peak load, plus the reserve margin resulting from the intersection of the VRR and the supply curve. Thus, the critical question is the extent to which reducing Pepco load in particular hours reduces PJM's forecast of Pepco load at future peaks.

Mr. Giovannini agrees that "the DP, CVR and EMT programs reduce capacity prices only to the extent that they reduce PJM's forecast of peak load" (OPC DR 8-16).

Q: Once the Pepco zone's capacity obligation for a delivery year has been determined, do reductions in customer loads affect the total obligation in the Pepco zone?

A: No. The Peak Load Contribution for each customer is determined by allocating the zonal obligation in proportion to the customer's contribution to PJM's highest-load hour in each of the five highest-load days in the previous summer (e.g., 2018 for the 2019/20 delivery year). But anything that a Pepco customer does to reduce its Peak Load Contribution simply shifts capacity obligation to other customers in the Pepco zone.

Q: Did Pepco activate the DP program on the days that determine customer Peak Load Contributions?

A: No. Table 6 lists the five highest-load days from 2013, 2014 and 2015, and the peak hour for each such day. Pepco did not call a PESC day on any of these fifteen days.[13]

Table 6: Days Determining Peak Load Contribution Allocation for Following Delivery Year

Year	Date	Hour
2013	15-Jul	6 PM
	16-Jul	5 PM
	17-Jul	5 PM
	18-Jul	5 PM
	19-Jul	3 PM
2014	17-Jun	6 PM
	18-Jun	5 PM
	1-Jul	6 PM
	22-Jul	6 PM
	5-Sep	4 PM
2015	20-Jul	5 PM
	28-Jul	5 PM
	29-Jul	5 PM
	17-Aug	3 PM
	3-Sep	5 PM

Q: What reductions in post-2012 loads would affect the forecasts of PJM's peak load, the reserve requirement, and Pepco's share of the capacity obligation?

A: That is a complicated issue.

Load reductions in the majority of the 365 observations for each recent year would tend to reduce the coefficients of variables that have been higher in the recent years than in previously years, such as the composite variables that include the rising quarterly economic index, partially offset by the declining indices for

[13] In addition, while Pepco assumes that the peak hour is always 5 PM, that was the peak hour in only about half these days, with the other days peaking at 3, 4, and 6 PM.

energy intensity. Those changes might tend to reduce the load forecast, since PJM expects the past trend in the indices to continue.[14]

Reductions in most of the days in a month will tend to reduce the binary variable for that month, and hence forecasts for peaks in that month. Since each month has over 500 observations in the data base, reductions phasing in starting in 2013 (and reflected in the BRA forecasts for the capacity years starting in 2017) would have only a modest effect in forecasts until long after 2020.

Similarly, reductions in most of the occurrences of a particular weekday will tend to reduce the binary variable for that weekday, and hence forecasts for peaks for that weekday. Since each weekday has over 900 observations in the data base, reductions phasing in starting in 2013 would have only a modest effect in forecasts for 2020.

Reductions that primarily occur in the worst weather conditions will tend to reduce the coefficient on the weather variables. Since there are so many hot summer days in the historical data, many years of load reductions would be needed to change the projections.[15] To further complicate the situation, if a load reduction occurs at the lower end of a THI spline, it will tend to increase the coefficient for that THI range; if the load reduction occurs on a day at the high end of a range, it will tend to decrease the THI coefficient.

Q: Were the PESC days that Pepco called for the DP program the days of the highest THI in the summers?

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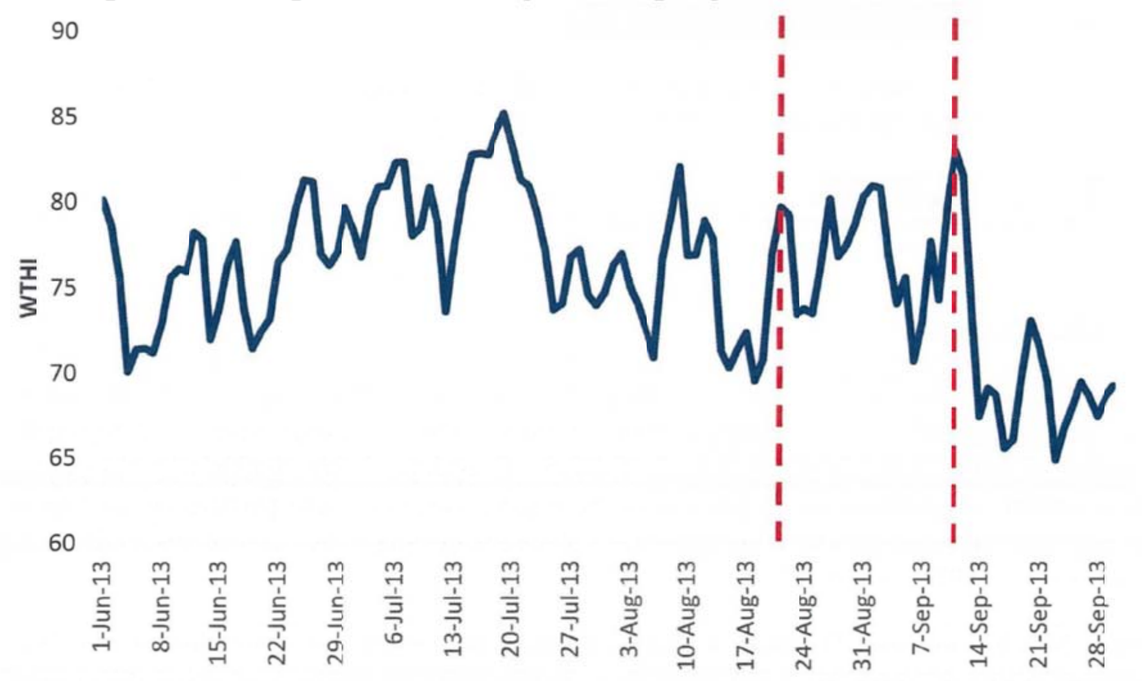
[14] The variable that includes the economic index and the index for cooling-equipment efficiency also includes the daily cooling degree days, further complicating predictions about the effect of DR load reductions in mild weather.

[15] This dilution effect is similar to the effects for the month and weekday binary variables, but more difficult to characterize, due to the multiplicity of weather measures and the range of values for each.

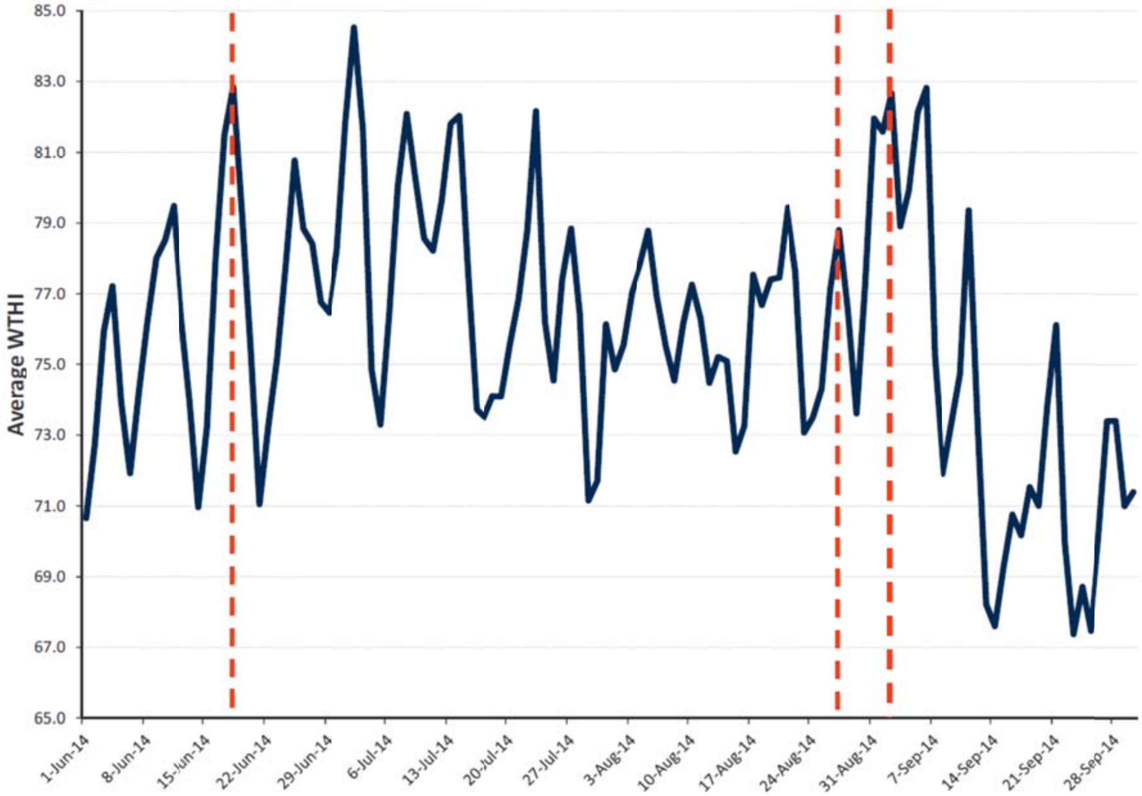
A: No. Figure 1 and Figure 2 show Pepco's estimate of the daily WTHI for each day of the summers of 2013 and 2014, respectively.[16] These figures also show the days on which Pepco declared DP events. In each year, Pepco missed the hottest day and declared a DP event on a modestly warm event.

Figure 1: Average WTHI from 1 pm through 6pm, 2013



[16] From OPC DR 3-8, Attachments A and B. Pepco has not provided comparable data for 2015.

Figure 2: Average WTHI from 1 pm through 6pm, 2014



Q: Did Pepco call PESC days on the PJM peak days?

A: No. In 2013, had the seventh- and fourteenth-highest PJM loads. The PESC days in 2014 were the second-, ninth- and 11th -highest PJM loads.[17] In 2015, the PESC days were the 16th, 23rd-, 28th-, and 30th-highest days. The PJM peak days were 20,000 MW higher than the peak on the average PESC in 2013, 5,900 MW in 2014, and 10,700 MW in 2015.

In addition to missing the extreme weather conditions, Pepco has been missing the highest PJM peak loads, which would have the highest effect on the PJM regression-based forecasts. The actual peak hours are listed in Table 6, above.

[17] In addition, several of the highest-load days were in January and February.

Q: Does Pepco acknowledge that the DP load reductions have missed the peak hours and worst-weather hours in all three years?

A: No. Bizarrely enough, Mr. Giovannini asserts that "Load reductions that do not reduce peak loads are not included" (OPC DR 8-18a), which is patently untrue. The DP program has never reduced Pepco's contribution to PJM peak loads, or to the Pepco peak loads.

Q: Is the hour ending 17 dependably the PJM peak hour?

A: No. The peak hour for one of the two 2013 PESC days was at hour-ending 15, and the peak hours for two of the four PESC days were at hour-ending 15 and 16. So not only did Pepco invoke the PESC on non-peak days, its assumption that only reductions at hour 17 matter is incorrect.

Q: Do the PJM forecasting regressions use loads normalized to an 83.7° WTHI?

A: No. The PJM forecasts use actual loads.

VI. Claimed Generation Capacity Benefits

A. Capacity Revenue

Q: Have you identified any problems in Pepco's estimates of capacity revenue?

A: Pepco's analysis assumes that its DP program will receive $44.81/MW-day in June–December 2019 and $45.59/MW-day in January–May 2020.[18] The actual prices for Pepco demand resources in the 2019/20 BRA was $0.01/MW-day in 2019/20. Using the actual 2019/20 capacity price reduces the AMI benefits by about $2 million.

[18] This change in price in the middle of a delivery year is inconsistent with PJM's rules and indicative of the sloppiness in Pepco's benefit analysis.

B. Avoided Capacity Cost

Q: How does Pepco estimate avoided capacity costs?

A: Pepco's analysis can be broken down into three steps. First, Pepco estimates a measure of peak load reduction, from each program, for the summers of 2013 through 2023, as follows:

- CVR: 1.1% of residential contribution to peak load plus 0.9% of non-residential contribution to peak load.
- EMT: 1.73% of Pepco Maryland residential contribution to peak loads.
- DP: An average of 166 MW for 2020 through 2023.[19]
- EWR: 2.2 MW for each year 2015–2023.

Second, Pepco assumes that each megawatt of DP load reduction in a particular year, other than capacity bid into the PJM auction, results in a megawatt reduction in the zonal capability responsibility for that capacity delivery year, through the rest of the analysis period. Pepco assumes these instantaneous benefits occur from 2020 onward. For the other three programs, Pepco lags the capacity benefit by 4 years.

Third, Pepco multiplies the assumed DP and EWR reductions by the Pepco zonal performance capacity price for 2018/19, escalated by a phenomenal 111% to 2020 and 2.1% annually thereafter, through 2023. For EMT and CVR, Pepco multiplies the assumed forecast reductions by the following prices:

- for each delivery year through 2018/19, the weighted average capacity prices in the Pepco zone for that year.
- For 2019/20, 110% of weighted 2018/19 price increase (which is overstated by about 60% for 2019/20).

[19] The load reductions prior to 2020 are treated as providing capacity revenue, rather than avoiding retail capacity charges.

- For 2020/21, 113% of the 2018/19 performance capacity price, and
- For 2021/22 and 2022/2023, the 2020/21 value escalated at 2.1% annually.

This mishmash of assumptions is inconsistent and fraught with errors.

Q: How do you address the problems in this analysis?

A: Mr. Chang will address issues in the first step (estimation of load reductions) in his testimony. In Section V.B, I discussed Pepco's error in imputing reductions in the Pepco zonal peak forecast and the Pepco capacity obligation to the DP and EWR programs. My testimony in this section concentrates on the timing of DP effects in the second step and Pepco's assumed prices for capacity.

1. Timing of Avoided Capacity Benefit

Q: How long does Pepco assume it takes for a reduction in peak retail load to affect the capacity obligation for customers in the Pepco zone?

A: For the DP program, Pepco assumes zero or negative delay, so a megawatt load reduction in the summer of 2020 reduces the capacity obligation by 1 MW starting June 1, 2020, before the load reduction occurs. For the other three programs, Pepco assumes a four-year delay, so a megawatt load reduction in 2014 reduces the capacity obligation starting June 2018.

Q: Is either of these assumptions realistic?

A: No. Capacity obligations are driven by PJM's forecast of zonal load for the delivery year, based on a load forecast developed three years earlier (prior to the BRA), based on load data from 1998 through the summer four years before the delivery year. Hence, the four-year delay assumed for the non-DP programs is a minimum lag in the effect. As discussed in Section V.B, the few days of DP and EWR load reductions have almost no effect on the Pepco forecast or capacity obligation, so these benefits are essentially zero. In connection with Case No. 9406, OPC asked PJM to model the load reductions that BGE estimated for its dynamic-pricing program. PJM ran its forecasting model with adjustments for about 100 MW in 2013, 200 MW in 2014 and 300 MW in 2015, and projected that the 2016 forecast for 2019 (when Pepco's model would have predicted a 300 MW reduction in load) would show a reduction in BGE's peak load of only about 5 MW. Pepco's estimates of avoided capacity obligations from the EWR and DP programs should be reduced by about 99% (or just set to zero), pending PJM's response to OPC's request for a Pepco-specific recomputation.

The CVR and EMT programs (if Pepco's savings assumptions are realistic) would start to reduce capacity obligations four years after the load reduction occurs, but the effect for the next several years would be much smaller than Pepco assumes. In connection with Case No. 9406, OPC also asked PJM to model the effect on the PJM peak forecasts of a reduction in BGE's load by 1% in each hour in 2013, 1.4% in 2014, and 1.5% in 2015. PJM found that this adjustment reduced the 2016 forecast for BGE 2019 peak by about 0.45%, while the Pepco method for CVR and EMT assumes that the reduction would be 1.5%, which is more than three times the reduction that PJM would actually recognize.

Q: What would be a realistic assumption regarding the effect of load reductions on capacity price mitigation?

A: Pepco's estimated reduction in capacity obligation should be eliminated for the DP program and reduced 70% for the CVR and EMT programs. These adjustments are in addition to the reductions in the price of capacity, discussed in the next section.

2. Avoided Capacity Costs

Q: What does Pepco assume will be the price of the generation capacity obligation avoided by load reductions?

A: For reductions in obligations in 2016/17 through 2018/19, Pepco uses a weighted average of prices for multiple types of capacity.[20] These values are broadly appropriate for capacity obligations in those years.

In 2019/20, Pepco assumed prices much higher than actually occurred, as shown in Table 7. For the five months of 2019/20 that are part of 2020, Pepco inflates its already-excessive value by 11% of non-existent inflation.

Table 7: Pepco-Zone Capacity Prices for EMT and CVR, 2019/20 BRA

	Pepco Assumption		Actual
	2019	2020	
Base Capacity	$149.98		$80.00
Performance Capacity	$164.77		$100.00
EE/DR Base Capacity	$41.09		$0.01
Weighted Average Avoided Cost	$150.10	$166.54	$91.64

For the rest of 2020, Pepco increases the 2018/19 performance-capacity price of $164.77/MW-day by 11% (allegedly for CPI inflation) to $182.81/MW-day, and then inflates the price 2.1% annually thereafter.[21] In 2019/20, the performance-capacity price fell to $100/MW-day. Since new generation units totaling 5,374 MW (in UCAP terms) cleared at the $100/MW-day price, including 2,275 MW in MAAC, even in a period with low expected energy revenues, that price appears sufficient to support building new generation. The $100/MW-day price would be a more appropriate starting point for prices after 2019/20.

[20] These prices are applied only for EMT and CVR, since DP and EWR capacity benefits are treated as revenues through 2019/10.

[21] The jump in 2019/20 appears to reflect Pepco's erroneous belief that the $164.77/MW-day was in 2015/16 dollars, rather than 2018/19 dollars.

Q: What is Pepco's position regarding the avoided capacity value of the DP program after 2019/20?

A: Pepco assumes that the DP program will avoid $182.81/MW-day, even though, as I have shown above, the DP program will not reduce Pepco capacity obligations.

> Pepco's DP resource … will be unable to earn PJM capacity revenue after May 31, 2020. However, Pepco will seek additional DP capacity market revenue in future years to the extent that evolving PJM capacity market rules permit it to do so. Additionally, Pepco will continue to work with Maryland stakeholders to determine the best method of funding the customer incentives for DP and deriving Maryland electricity customer value. For cost effectiveness modeling, Pepco has assumed that no PJM capacity market revenue will be available to fund DP after May 31, 2020, which is the end date of PJM Delivery Year 2019/20. (Giovannini Direct at 8–9)

Nonetheless, Pepco assumes that the DP will be worth $183/MW-day in 2020, escalating at inflation.

Q: If "Pepco has assumed that no PJM capacity market revenue will be available to fund DP after May 31, 2020," what does the $183/MW-day value represent?

A: Mr. Giovannini (Direct at 9) suggests that the DP program could be subsidized in one of three ways:

1. establishing a demand response portfolio standard, requiring wholesale electric suppliers to fund DP,
2. collecting funding through the EmPOWER surcharge on electric distribution bills,
3. converting the existing DP Program from a rebate program to a critical peak pricing program.

He elaborates on these options in OPC DR 8-9.

Q: Would these options represent real benefits that should be included in cost-effectiveness screening?

A: No. Options 1 and 2 simply propose ways to force consumers to pay for the DP program, without establishing that it actually creates any value. Option 3 is not a substantial change from the current program design, and would not create any new benefits. Pepco has not been able to time the DP hours to capture high-priced energy, reduce loads at the PJM peaks, or reduce peak transmission loads, and Mr. Giovannini does not explain how Pepco would improve its performance. Indeed, reducing the capacity obligation significantly would require many PESC days each summer, which would probably seriously erode customer response.

Q: How much does correcting these prices affect Pepco's claimed benefits?

A: Correcting the market prices to $91.64/MW-day in 2019/20 and $102.10/MW-day in 2020/21, escalating 2.1% annually through 2023/24, reduces the present value of Pepco's capacity benefits by $18 million.

C. Capacity Price Mitigation

Q: How does Pepco estimate the effect of the programs on the capacity prices paid by consumers.

A: Pepco includes capacity-price effects of:

- DP for 2013 through 2018, assuming that the price effect is experienced in the year that the resource cleared in the BRA and lasts four years or through 2018, whichever is earlier.
- EMT for 2016 through 2022, assuming that the price effect is lagged by four years from the date of incremental load reductions (i.e., from the load reductions in 2012 to a price effect in 2016).

- CVR for 2018 through 2023, using the timing assumptions for EMT[22] adjusted for a PJM-mandated reserve margin.[23]

Pepco multiplies these assumed reductions in peak loads by an annual coefficient that is the product of the following two factors:

- The zonal capacity obligation in each BRA of Maryland load (BGE, SMECo and the Maryland portions of Potomac Edison, Pepco and Delmarva,[24] and
- A coefficient that Pepco presents as representing the change in the BRA clearing price for premium capacity in $/MW-day per megawatt of low-cost capacity added to the supply curve in the BRA or per megawatt of load reduction.

Q: What problems have you identified in Pepco's estimate of capacity price mitigation?

A: I have identified five errors in Pepco's analysis. First, as I explained in Section V.B, the DP load reductions will not substantially affect the amount of capacity that PJM acquires, so those reductions will have no effect on capacity prices. PJM's modeling of an load reduction similar to those claimed by PEPCO for the EMT and CVR programs also indicates that those will affect the PJM capacity

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[22] Pepco estimates that the CVR load reductions start two years later than the EMT reductions, and that the CVR reductions increase through 2019, pushing the price effects through 2023, while the EMT reductions plateau in 2017, so the price effects end in 2022.

[23] The durability of the price effect is difficult to directly observe or estimate and Pepco's four-year estimate falls in the range I have seen elsewhere.

[24] Pepco omits the Potomac Edison load in 2013/14 through 2016/17, when MAAC cleared at higher prices than AP, and Delmarva load in 2018/19, when EMAAC separated from the rest of the system. Pepco fails to make the Delmarva correction in 2013/14 or 2019/20, when EMAAC also separated from Pepco and the rest of MAAC.

requirement and the price of capacity much less and much more slowly than Pepco assumes.

Second, the load forecast that Pepco uses to estimate the amount of capacity that Maryland customers will bear (and hence the effect of a price reduction) is much higher than PJM's current forecast, as described in Section III.

Third, Pepco assumes that prices for Delmarva will always be affected by Pepco loads in future BRAs.

Fourth, the coefficients that Pepco uses to convert load reductions and cleared resources to price reductions is significantly overstated.

Fifth, the price reduction from adding the demand resources to the capacity auctions are often less than the reduction from adding generation or other premium resources.

Q: How are capacity prices for the Delmarva zone affected by changes in Pepco load?

A: That varies from auction to auction, depending on supply and demand conditions in the zones. The EMAAC LDA, including Delmarva, has separated from SWMAAC and the RTO in four of the last eight BRAs, including the two most recent auctions (2018/19 and 2019/20). Pepco excludes capacity price benefits for the Delmarva zone in 2018/19, since reductions in Pepco load would not have allowed any additional capacity to be supplied to Delmarva, so Delmarva's capacity price would not have declined in response to lower forecast Pepco load. Pepco should have done the same for 2013/14 and 2019/20.

In most situations in which no specific information is available, Pepco's analysis continues the last known value, or escalates it at the assumed inflation rate. If Pepco had used that approach, it would have assumed that EMAAC would continue to be separate from MAAC and the RTO zone, and thus not be affected by reductions in Pepco load or increases in supply. Instead, Pepco assumes that Delmarva will always share the RTO capacity price in 2019/20 through 2023/24. A more reasonable estimate might be that EMAAC would separate from the RTO in half the years, so the reductions in Pepco load would, on average, reduce prices for about 5% less Maryland load than Pepco has assumed.

Q: How did Pepco estimate the capacity-price mitigation coefficient?

A: Pepco assumes that the reduction in price in $/MW-day per megawatt of load reduction or cleared capacity will be 50% of the slope of the steeper portion of the Variable Resource Requirement (VRR) curve. Pepco presents no evidence to support this value, and has conducted no supporting analysis (OPC DR 8-20A.).

Q: What is the origin of this approach?

A: The MEA invented it in the EmPOWER consultation process, also without any analytical support, other than the fact that it is half-way between zero and the slope of the VRR.

Q: How should the capacity-price mitigation coefficient be estimated?

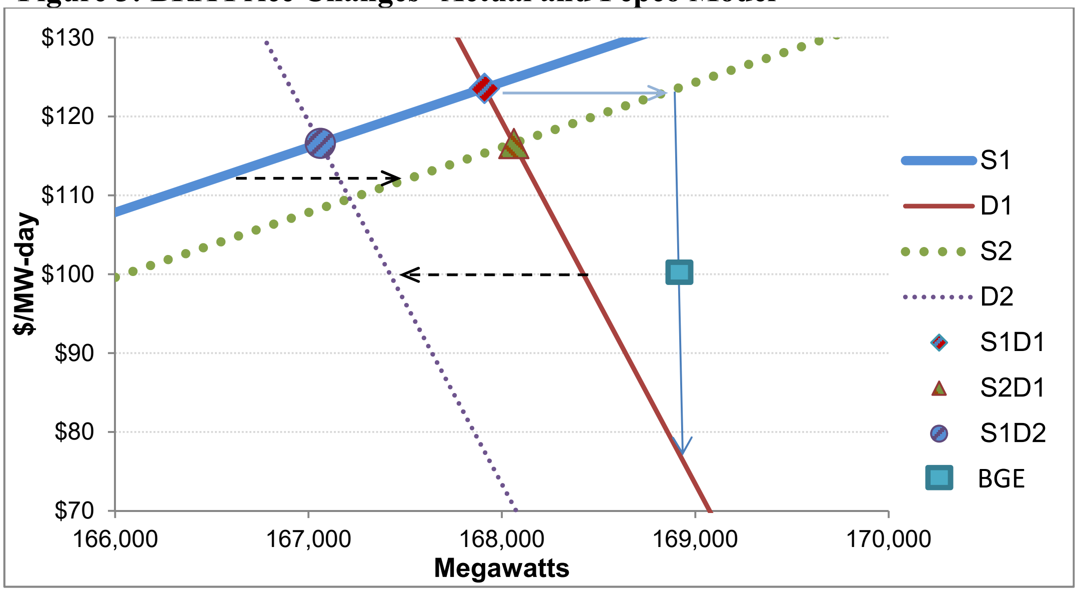
A: The $/MW-day/MW coefficient should reflect the operation of the PJM capacity auction. Figure 3 illustrates the operation of the RPM market, or any other simple matching of supply and demand.[25] This illustration could be right out of an introductory economics text.

Figure 3 illustrates the effect of adding 1,000 MW of peak reduction to the RTO market as an increase of supply (shifting the S_1 supply curve to the S_2 supply curve) or a decrease in demand (shifting the D_1 VRR curve to the D_2 VRR curve).

[25] For ease of presentation, this example ignores the multiple types of capacity acquired at different prices in some PJM auctions, as well as the multiple pricing zones. As I discuss below, the capacity product that Pepco has bid into some of the auctions has little or no effect on the price paid for most of Maryland's capacity obligation.

The dashed lines show a 1,000 MW shift in the supply curve to the right, or the demand curve to the left.

Figure 3: BRA Price Changes--Actual and Pepco Model



In addition to the actual clearing price (point S_1D_1), Figure 3 shows the effect of shifting the supply curve 1,000 MW to the right (point S_2D_1, reflecting addition of 1,000 MW of low-price premium capacity into the auction) and the effect of shifting the demand curve 1,000 MW to the left (point S_1D_2, reflecting 1,000 MW reduction in the demand curve from reflecting the same amount of reduction in the forecast driving the demand curve). In each case, the 1,000 MW shift reduces the market-clearing price by about $7/MW-day.

The Pepco method, on the other hand, would estimate a $23 reduction in price, also shown in Figure 3. The Pepco method is uniformly biased upward.

Q: How should this coefficient be estimated?

A: There are two viable approaches to modeling the auction:

- Using available data on the VRR and the supply curve to find the new market-clearing prices following a load change. Since PJM released only graphic representations of the supply curves by zone and (where relevant) resource type for the 2014/15, 2015/16, and 2016/17 BRAs, this method requires some approximation and it is limited to those three years.[26]

- Relying on the sensitivity analyses performed by PJM following the 2014/15, 2015/16, 2016/17, 2017/18 and 2018/19 BRAs. Since PJM has all the price bids and all the rules it uses in setting the market-clearing price in each zone, these results should be very accurate. Unfortunately, the sensitivity studies do not cover all interesting types of load reductions (in this case, a reduction in Pepco load and additions of demand response in the Pepco zone) and are generally for changes larger than the effects Pepco claims for its programs.

Q: Has the first method been implemented?

A: Yes. As discussed in the MEA's EmPOWER 2015–2017 Cost Effectiveness Framework and demonstrated in the VRR Curve Capacity DRIPE table (included in OPC DR 8-20), MEA estimated the slope of the Variable Resource Requirement (VRR) curve (the administrative equivalent of a demand curve) from PJM filings of Planning Period Parameters documents, and the supply curve from graphics that PJM has provided for three BRAs.[27] Table 8 compares the coefficients used by Pepco for those years with the coefficient that results from determining the new equilibrium price. I present only the MAAC results, since Pepco models only the effects on prices in MAAC for those years.[28]

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[26] BGE does not have any information regarding the actual slope of the capacity supply curve. (OPC DR 4-28)

[27] 2014/2015 Base Residual Auction Report Addendum, 2015/2016 Base Residual Auction Supply Curves, and 2016/2017 Base Residual Auction Supply Curves, all available at www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/.

[28] This treatment ignores the effect on Potomac Edison customers resulting from the effect of MAAC load and supply on the RTO clearing price.

Table 8: Comparison of Pepco and Equilibrium Price Response to Load Reductions ($/MW-Day/MW)

	2014/15	2015/16	2016/17
Pepco Approach	$0.0386	$0.0431	$0.0443
New Equilibrium	$0.0338	$0.0266	$0.0167

A realistic assessment of the change in prices, using only the VRR and supply-curve data that PJM has released, would result in price reductions about 12% less than Pepco assumed for 2014/15, 38% for 2015/16, and 62% for 2016/17.

Q: Do the PJM sensitivity analyses provide a more comprehensive view of the capacity price-mitigation effects than the graphical analysis whose results you present in Table 8?

A: Yes. The results in Table 8 rely on visual estimation of the supply slope from a graph that PJM manipulates to obscure individual bids, are available for only three years, and cannot directly estimate the effect of Pepco load and resources on prices for AP (or in some years, Delmarva).

The PJM sensitivity analyses represent PJM's hypothetical reruns of the BRA, adding or subtracting various amounts of low-price capacity in one or more LDAs.[29] The results should reflect all the complexities of the operation of the PJM capacity auctions, including the VRRs, supply curves, and constraints on Limited and Extended demand resources in each of the modeled zones and LDAs. Table 9 shows the $/MW-day change in price in various LDAs for subtracting a MW of supply in the Pepco zone.[30] Table 9 shows the type of capacity removed from the bottom of the supply curve, the smallest LDA containing Pepco for which supply

[29]The sensitivity analysis for each BRA is available at www.pjm.com/markets-and-operations/rpm/rpm-auction-user-info.aspx, under the drop-down list for that BRA.

[30]Where PJM modeled multiple changes (e.g., ±2,000 MW and ±4,000 MW), I use the slope for the smaller range, to better represent the scale of energy-efficiency programs.

decreases were modeled, the size of the decrease, and the increase in price of the premium supply (Annual Supply in the first four auctions, Capacity Performance in 2018/19) divided by the reduction in supply ($/MW-day/MW).[31]

Table 9: Summary of PJM Sensitivity Analyses for Supply Decreases

Year	Type of Supply Removed	Modeled LDA	MW Δ	Price Change ($/MW-day) for 1-MW Δ in Pepco Zone		
				RTO	EMAAC	SWMAAC
2014/15	Annual	SWMAAC	–500	0.0252	0.0165	0.0165
	Limited	SWMAAC	–500	0.0050	-0.0048	-0.0048
2015/16	Annual	SWMAAC	–750	0.0027	0.0367	0.0367
2016/17	Annual	SWMAAC	–750	0.0030	0.0140	0.0140
2017/18	Annual	MAAC	–3,000	0.0094	0.0094	0.0094
2018/19	Performance	MAAC	–3,000	0.0049	0.0045	0.0049

In the first three relevant years, PJM modeled supply changes in the SWMAAC region (among others); in the last two years, PJM modeled supply changes distributed among the zones of MAAC, but not for SWMAAC alone. For 2014/15, PJM modeled reductions in both annual supply (generation and some demand resources) and Limited Demand Resources.

Q: Did Pepco explain why it did not use the results of the PJM sensitivity analyses?

A: No, only that it relied on the Commission's acceptance of the half-of-VRR value for screening of the 2015–2017 EmPOWER Maryland programs (OPC DR 8-19).[32] Since the DP load reductions are very different from the energy-efficiency

[31] The premium supply represents most of the capacity procured in each year, and BGE uses the premium-supply price in its analysis of capacity price suppression.

[32] The Commission's order accepted this approach for just one EmPOWER program cycle and noted that the EmPOWER "DRIPE methodology may be revisited in conjunction with subsequent program cycle planning following completion of additional analyses as recommended by Staff." (Order No. 87082, Case Nos. 9153, et al., at 13) The current proceeding does not concern the evaluation of the EmPOWER programs, and my testimony provides additional analyses.

load reductions modeled in the EmPOWER Maryland analysis, and bid into the auctions as an inferior product, and a majority of the capacity revenue is from auctions that have already occurred, the EmPOWER analysis is not applicable to the cost-benefit review of the smart meters.

Q: What is the significance of the negative signs in the "Limited" line for 2014/15?

A: The PJM sensitivity analysis indicates that removing 500 MW of Limited Demand Resources reduces the Annual Supply price for the RTO, but increases that price for SWMAAC and EMAAC. The reduction in Limited Resource supply increases the price of Limited Resources in all three LDAs (by about $0.0047/MW-day per MW), but Limited Resources are only about 15% of SWMAAC supply and 7% of EMAAC supply.

Q: Is it surprising that removing Limited resources does not increase the price of Annual Resources?

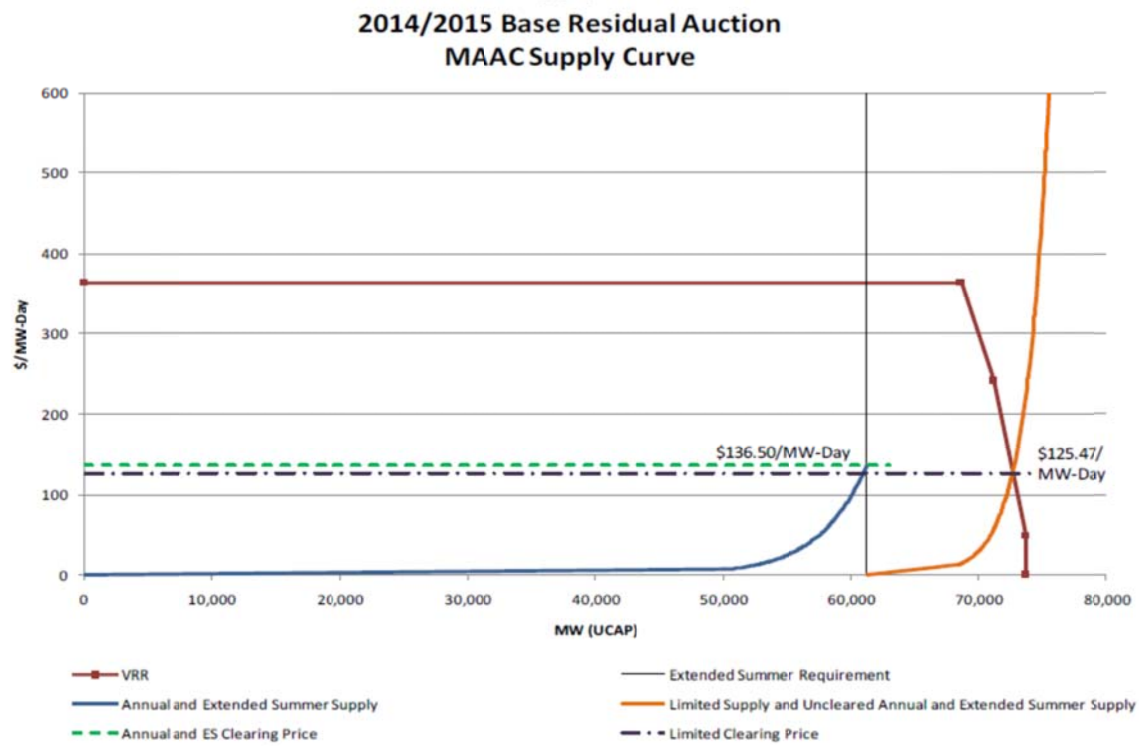
A: No. I would expect that, whenever Limited resources cleared at a significantly lower price than Annual resources, reducing the supply of Limited resources would increase only the Limited price and not the Annual price. PJM restricted the amount of Limited resources it would allow to clear in the market (for the RTO and for various LDAs).[33]

Figure 4 illustrates the split clearing for SWMAAC Limited resources in 2014/15, while Figure 5 illustrates the split clearing for MAAC Limited resources in 2015/16. Pepco's DP resources cleared as Limited resources in both those years

[33] PJM imposed limits on the amount of Extended Summer resources, but those constraints do not appear to have been binding in the years and zones of interest in this analysis. In the 2018/19 BRA, PJM imposed similar constraints on Base supply, resources that do not meet the Capacity Performance requirements.

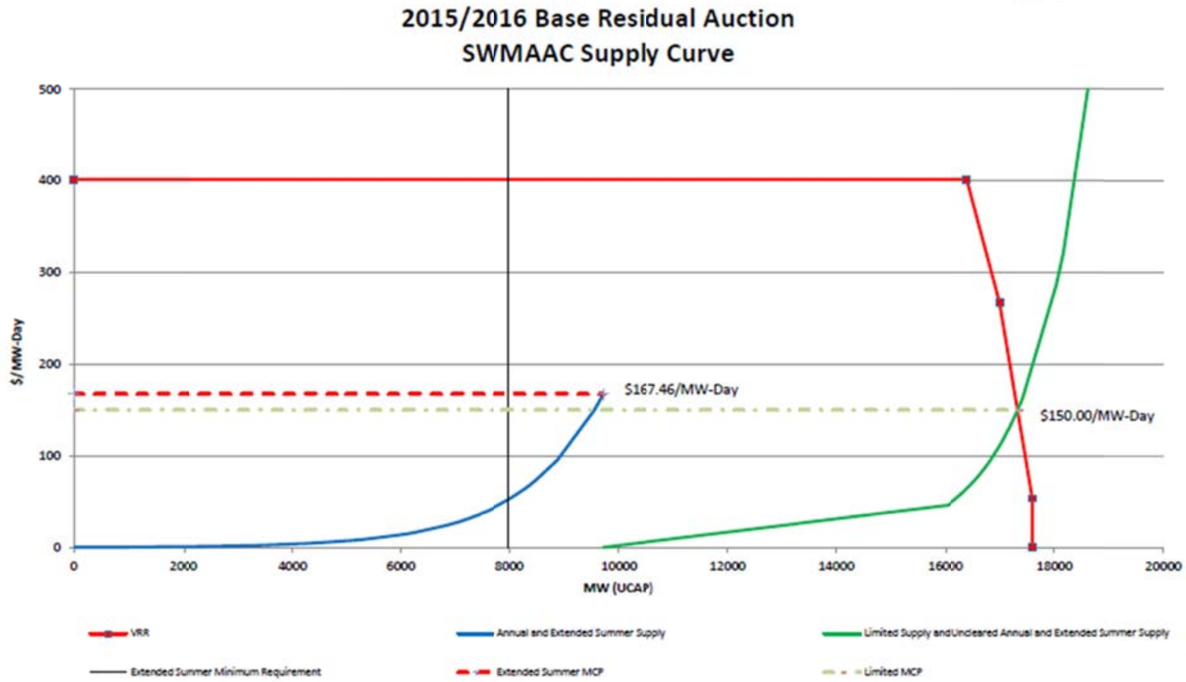
and cleared at prices below Annual resources. From those graphics, it appears that hundreds of megawatts of Limited resources would need to be withdrawn before the price of the Annual resources would rise at all. It is unlikely that the 175 MW or so of DP capacity had any effect on the prices of the annual or extended-summer resources. In 2018/19, the DP program was a Base resource, and 2019/20 it was a Base DR resource, both of which cleared far below the price of performance capacity. Only in 2016/17, when all resources cleared at the same price, and 2017/18, when the DP program cleared as an Extended resource at the same price as Annual resources, would the cleared DP capacity have reduced the price for the dominant class of capacity resources.[34]

Figure 4: Separation of Limited Supply Price, 2014/15 MAAC Supply Curve



[34] Pepco identifies the type of capacity for which it offered the programs in OPC DR 8-3b and c.

Figure 5: Separation of Limited Supply Price, 2015/16 SWMAAC Supply



PJM has not released supply curves for 2018/19 or 2019/20, but the clearing price for the DP capacity was 60% lower than the price for Capacity Performance in 2018/19 and 99.99% lower than the price or Capacity Performance in 2019/20, so it is unlikely that removing the small amount of cleared DP capacity from these auctions would have affected the Annual price.

Q: What type of resource did PJM allow Pepco's DP program to clear as?

A: The DP resource cleared as a Limited resource in 2013/14 through 2015/16, as a Base resource in 2018/19, and as a Base Demand resource in 2019/20. In 2013/14, Limited resources received the same price as did Annual resources, but in the other four years, the DP program received a lower price than the majority of capacity.

Q: How does Pepco reflect the fact that the DP resources were not Annual resources in 2014/15 and 2015/16 or Capacity Performance resources in 2018/19 and 2019/20?

A: Apparently ignorant of the operation of the PJM capacity markets, "[t]he Company has assumed that all cleared supply-side resources will have an effect on all wholesale capacity market prices." (OPC DR 8-18c)

Q: Is the change in price the only effect of changing the amount of demand resources that Pepco sells into the capacity market?

A: No. PJM developed the VRR to increase the amount of capacity procured as price falls and decrease the amount procured as price rises. If Pepco had not bid the DP program into the capacity market, some prices would have been higher, but the amount of capacity procured and hence the capacity obligation for BGE, Pepco and (in some years) Delmarva and Potomac Edison would have been lower. Pepco has not taken this effect into account.

Q: What are your best estimates of the price-mitigation coefficients applicable to reductions in peak load and to demand response bid into the capacity auctions?

A: Table 10 summarizes my recommendations, before any adjustment for the offsetting increase in capacity obligation as prices fall. Load reductions would have the effects summarized in Table 9, while the cleared resources provide less (or negative) benefit in 2014/15 and no benefit in 2015/16 and 2018/19. Cleared demand resources have full benefits in 2016/17, when the resources cleared at the same price as other resources, and 2017/18, when Pepco bid the programs as Extended Summer resources, which cleared at the price of Annual resources.

Table 10: PJM Estimate of Pepco Dynamic Pricing Effect on Capacity Prices ($/MW-day/MW)

Year	Pepco modeled as part of	Load Reductions			Cleared Demand Resources		
		PE	DPL	+ BGE Pepco	PE	DPL	+ BGE Pepco
2014/15	SWMAAC	0.0252	0.0165	0.0165	0.005	-0.0048	-0.0048
2015/16	SWMAAC	0.0027	0.0367	0.0367	–	–	–
2016/17	SWMAAC	0.0030	0.0140	0.0140	0.0030	0.0140	0.0140
2017/18	MAAC	0.0094	0.0094	0.0094	0.0094	0.0094	0.0094
2018/19	MAAC	0.0049	0.0045	0.0049	–	–	–

PJM has not yet released a sensitivity analysis or supply curves for 2019/20, but we can be pretty certain that the DP program would not have any effect on prices in 2019/20, given that DP cleared at near zero.

Note that I include price benefits for Potomac Edison in 2014/15 through 2016/17 and Delmarva in 2018/19. The Delmarva coefficient for 2018/19 is exaggerated by PJM modeling of simultaneous reductions in all parts of PJM, including EMAAC; a reduction just in the Pepco zone would almost certainly have little effect on the price in EMAAC, which was priced 37% higher than the SWMAAC price.

Q: What effect does this last correction have on Pepco claimed benefits?

A: The corrected price-mitigation coefficients decrease BGE's claimed price-mitigation benefits by over $103 million in present value, even without reducing the claimed DP load reductions, reflecting the lag in the effect of the DP, reducing the program effects on capacity obligation, updating the load forecasts, or incorporating the increased capacity obligation due to reduced price.

Q: Please summarize your review of the effect of the DP programs on capacity prices.

A: The DP program is unlikely to produce any meaningful capacity-price benefits. The EMT and CVR programs may produce some price benefits, but substantially less than Pepco assumed, since Pepco overestimated the sensitivity of the load forecast to recent load reductions and the response of price to reductions in forecast load. Zeroing out the price mitigation effects of the DP program and reducing the EMT and CVR effects on capacity obligation by 70%, to be consistent with the PJM methodology, reduces the capacity price mitigation benefit by another $56 million in present value.

VII. Claimed Transmission and Distribution Benefits

Q: What problems have you identified regarding Pepco's estimates of transmission and distribution benefits?

A: I have identified three such problems. First, Pepco developed a carrying charge that should be levelized in nominal dollars, but escalates over time. Second, no T&D projects were avoided in the years in which Pepco claims large avoided capital costs.[35] Third, the DP program does not result in decreased loads at the times of peak loads on the lines that Pepco uses in estimating avoided transmission costs, and hence cannot reduce transmission peak loads or avoid transmission costs.

Q: Please explain Pepco's error in the development of the T&D carrying charge.

A: In Staff DR 6-1, Attachment K, Pepco derives a 9.9% levelized carrying charge for T&D. This is a nominally-levelized rate, computed from the observation that $9,895 annually, discounted at Pepco's 8.01% nominal rate of return, would have the same present value ($119,364) as the revenue requirements (return, taxes,

[35] I t is also not clear that all of the claimed T&D cost savings for 2012–2014 would have flowed through to consumers, given the timing of rate cases. Reductions between the effective dates of rate cases would have been retained by Pepco Holdings shareholders.

depreciation and insurance) of a $100,000 investment. That computation is for $9,895 each year, without inflation.

Yet Pepco does not apply the carrying charge in nominal terms. It escalates the avoided T&D with inflation, effectively assuming that the $100,000 investment would require cost recovery of $9,895 in year one, $10,100 in year two, $10,310 in year three, and $24,180 in year 44. This stream of revenues would have a present value of $156,562, 31% higher than the revenue requirements of the original $100,000.

Q: If Pepco had wanted to properly use escalating avoided T&D costs, how should it have computed the carrying charge?

A: The economic, or real-levelized, carrying charge for Pepco's inputs and a $100,000 investment, would be $7,544 (7.5%) in year one, not $9,895 (9.9%), increasing by 2.1% inflation to $7,700 in year two and $18,400 in year 44. That real-levelized, inflating cash flow would also have the same present value of $119,364 over 44 years as the revenue requirement or the nominally-levelized avoided cost.

The real-levelized avoided cost is generally more flexible and easier to use properly than the nominally-levelized avoided cost, and produces more accurate results for periods shorter than the life of the equipment. But regardless of which approach Pepco might choose, it cannot combine the higher initial carrying charge, the nominal carrying charge and the inflation of the real-levelized carrying charge.

Q: How should the avoided T&D costs be adjusted to correct the error in Pepco's computation of the carrying charge?

A: The avoided T&D costs should be reduced by 24% to correct this overstatement.

Q: For what years does Pepco claim that the AMI programs have avoided T&D investments?

A: Pepco claims that the AMI programs reduced T&D costs by about $11 million annually by 2013 and $12 million annually by 2015. Since these saving are estimated using a 9.9% carrying charge, Pepco must be claiming that it avoided $111 million in T&D projects in 2012 and 2013, and $122 million in 2014 and 2015.

Q: How long a delay does Pepco assume between a reduction in load due to the AMI programs and the avoidance of T&D investments?

A: Pepco assumes that these programs avoid T&D costs in the year that they reduce loads.

Q: When would Pepco have needed to forecast the AMI load reductions in order to avoid investments in 2012 and 2013?

A: Pepco would have needed to anticipate the load reduction in 2009 or 2010. In order to avoid T&D investments, Pepco would need to explicitly adjust load forecasts to account for the DP loads, which do not occur in most hours, and forecast the resulting load at the time of the line or substation peak. Pepco would also need to forecast the effect of DP, EMT and CVR on load trends about three years in advance; for example, Staff DR 9-17 shows spending for the National Harbor substation starting in 2016 for a 2019 in-service date and for the Melwood substation starting in 2019, four years before the 2023 in-service date shown in Staff DR 9-7.

It is hard to believe that Pepco knew the magnitude of the load reductions it would estimate for 2012 and 2013 back in 2009 or 2010.

Q: What is your basis for saying that Pepco cannot identify any projects avoided in the years in which Pepco claims large avoided capital costs?

A: Pepco acknowledges that "Pepco has not fully eliminated any projects from either the distribution or transmission capital budgets because of AMI" (Staff DR 9-38). Staff DR 9-7 asked Pepco to identify the T&D projects that have been deferred; Pepco identified four distribution substations and no transmission investments.

Of the four deferred transmission substation investments, Pepco attributes three delays entirely to delay in major customer construction projects, and not to AMI programs, as follows:

- Melwood Substation: "contingent on significant construction in the Westphalia Town Center Development."
- Kingswood Substation transformer upsizing: "initially contingent on the Westphalia Town Center and nearby residential development. The project was subsequently advanced through the ECA Process."[36]
- National Harbor Substation: "contingent on the National Harbor development."[37]

For the fourth project, a new White Flint/Grosvenor substation, PEPCO attributes the delay from 2018 (originally proposed in 2012) to 2020 to "delays in construction of projects in the White Flint area and in reduced usage" (Staff DR 9-7) and "delays in customer projects, energy efficiency improvements, and energy reductions caused by the implementation of AMI programs" (Staff DR 9-4).

Q: Is it possible that the delay in the White Flint/Grosvenor substation is attributable to the AMI programs?

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[36] The project was proposed in 2010 for implementation in 2015, was delayed to 2019, and then advanced to 2017 by the Equipment Condition Assessment process.

[37] Staff DR 9-5 elaborates on the adjustment of this substation "based on the developer's construction activities in National Harbor."

A: That is unlikely. Pepco offers no evidence that AMI had any effect on the delay. The "White Flint area" appears to be dominated by large commercial loads, so the residential AMI programs are unlikely to have been decisive in deferring the project. The "reduced usage" would include the closure of the White Flint Mall in 2015, unrelated to the AMI programs.

Q: Did the delay of the White Flint/Grosvenor substation (for whatever reason) save any distribution costs in 2012 through 2017?

A: No. The project was originally planned for 2018, so it's delay could not produce the savings that Pepco claims in 2012–2017.

Q: How much does Pepco expect the White Flint/Grosvenor substation to cost?

A: Pepco projects that the substation will cost $40 million (Staff DR 9-17), $43 million (Staff DR 6-1, Attachment N, Dist Calc tab) or $53 million (Staff DR 6-1, Attachment N, Pepco_AvgTnD tab).

Q: How does the cost of this substation, the only transmission or distribution project that Pepco suggests might have been slightly delayed by the AMI program, compare to the avoided T&D investment that Pepco claims?

A: Even in the unlikely event that the White Flint/Grosvenor substation were to be delayed a year by AMI savings (from 2019 to 2020), the high end of Pepco's estimates for that substation would only account for about 40% of the investment that Pepco claims to have avoided in 2015–2023; even that value should be reduced by about 24% to reflect Pepco's error in its carrying charge. This cost would have been avoided in the one year 2019 (if at all), rather than the eleven years for which Pepco claims savings. In 2019, the avoided T&D cost would be $58/MW-day.

Q: What can you conclude about the T&D benefit of Pepco's claimed AMI load reductions?

A: The investments that Pepco claims to have avoided through 2016 never existed. A small amount of investment may have been shifted from 2019 to 2020. Some projects may be deferrable by the AMI programs in 2021–2023, but Pepco has not identified any such projects in this time period.

Q: Please elaborate on your third point, the failure of the DP load reductions to affect most of the peak loads on Pepco's transmission facilities.

A: In OPC DR 16-18, Pepco provided the time of peak loads on each of its 230 kV and 500 kV transmission lines; Pepco computes its avoided transmission cost by inflating the original costs of the 230 kV and 500 kV system. Of the 95 or 96 lines for which Pepco was able to provide load data, only 5 experienced their peak loads in the PESC hours in 2013, and one each in 2014 and 2015. No line peaked in the PESC hours every year. Indeed, most of the lines either peak before or after the late-afternoon PESC hours of 1500 to 1800, or outside the summer period (June to September). Only 19 lines hit their peak load in the summer late afternoon hours of 2013, 22 in 2014 and 33 in 2015, and most of those missed the PESC days. About 40 lines peaked outside the summer months each year.

In addition to missing the system peak hours, Pepco's PESC days have missed the peak loads on the transmission lines. Thus, even if there were avoidable transmission costs, the DP program does not affect peak loads on the transmission lines.

Q: Do you have any additional information regarding the effect of reductions in peak substation loads due to the load reductions from the DP program?

A: Not much. When asked for the "date, time and megawatt load for the all-time peak demand on each distribution substation," Pepco provided only its "T&D Ten Year Forecast 2014-2023," which does not include the date or time of any facility peak loads. (OPC DR 16-24, citing Attachment 16-7). The only useful information in that document is the fact that a couple of Pepco's Maryland substations peak in the winter and thus will not be affected by the DP program.

In my analysis of BGE's dynamic-pricing program, I found that the operation of that program missed both the transmission-line peak hours (as is true for Pepco) and most of the distribution substation peak hours, as well as shifting some load onto the peak hours of some distribution substations. The same is likely for Pepco's distribution system; Pepco acknowledges that 50% of the energy reduction in the PESC hours is shifted to later hours (OPC DR 12-4f).

Q: Please summarize your conclusions regarding the avoided transmission and distribution investments from Pepco's AMI programs.

A: It is unlikely that any of the programs have produced any such benefits, or will do so through 2018. The EMT and CVR programs might yield a small distribution benefit in 2019 (about $58/MW-day), and possibly some transmission and distribution benefits in 2021 and 2023. Without any specific information about deferrable capacity after 2020, it seems reasonable to use Pepco's values, corrected for the carrying-charge error to $139/MW-day in 2015 dollars (76% of Pepco's estimate).

VIII. Claimed Energy Benefits

A. Energy Revenue

Q: How has PEPCO calculated energy revenues from the AMI programs?

A: Pepco includes energy revenue from the DP program as an operating benefit (OPR 19) for years 2012–2015, although it sometimes refers to the energy revenue as part of avoided energy costs, as in the DP tab of Attachment C. The energy revenues are entered in Attachment C as values, which tie back to the "pro rata energy" PJM settlement values reported in OPC DR 8-11 Attachment. I assume those revenues were actually passed on to customers. After 2015, Pepco appears to treat the DP energy effects as avoided energy costs.

B. Avoided Energy Costs

Q: How has PEPCO calculated avoided energy benefits achieved from the PESC event days?

A: The DP energy value is included as a demand-side benefit for years 2016–2023 (DSM 09), although they could have been treated as revenues.[38] The DP energy benefit is calculated as Pepco's estimate of the energy-use reduction from PESC participants multiplied by an assumed market price for the event hours.

Pepco computes EMT and CVR energy benefits as the product of the estimated energy reduction multiplied by estimates of the energy portion of supplier generation charges. The approach for these programs is straightforward and appears reasonable.

Q: What concerns do you have regarding the calculation method for determining the avoided energy from PESC event reductions?

A: I have several concerns regarding the avoided energy calculations from PESC event reductions, particularly Pepco's unexplained values and assumptions. Pepco does not explain or document most of its computations in Attachment C; while I have repeatedly requested clarification through discovery (OPC Data Requests

[38] While Mr. Giovannini (Direct at 13) asserts that "Due to the January 25, 2016 U.S. Supreme Court Decision No. 14-841, DP derived energy reductions remain eligible to receive PJM energy market revenue and therefore are not included as an avoided energy benefit," Attachment C and Ms. Lefkowitz's Table F include all post-2015 DP energy savings as avoided energy benefits, rather than revenues.

DR 8-7, DR 8-8, DR 8-14, DR 8-22), the responses have only referred back to Attachment C. My concerns are the following:

- Pepco assumes an enormous jump in the energy savings in 2016, without any explanation, compared to earlier years, and further escalates the savings after 2016. In 2015, the dynamic pricing event energy reductions totaled 598 MWh; Pepco assumes that value almost doubles in 2016 to 1,112 MWh.
- The calculations in the Dynamic Pricing Benefits_1 tab of Attachment C computing the savings for 2016 are based on the Pepco's "PJM BRA Capacity Mkt Position" for 2015/16 (as reported in OPC DR 8-3) multiplied by factors of 0.8, 0.5 and 16. The factor of 16 probably reflects the sixteen hours of PESC incentives that Pepco expects to offer annually in the future, and the 0.5 factor reflects the "snapback" of usage outside the PESC hours (OPC DR 12-4f).
    - There is no obvious relationship between the capacity that Pepco has bid into past BRAs and the energy savings Pepco reports.
    - The capacity cleared in the BRA is greater than the demand reductions Pepco estimates from the Brattle regression model, so it is not clear why Pepco started with the higher capacity value.
    - There will be no cleared DP capacity past 2019/20, yet Pepco continues this projection to 2022/23.
- Even more important than the unexplained doubling of energy savings is Pepco's projection of a fourfold increase in the value of energy during the PESC hours, from 2015 to 2016, with continued 2.1% inflation to 2023. Pepco assumes the energy price will be $200/MWh in those hours, even though the average value of avoided energy prices during event hours in 2014 was $75/MWh and for 2015 was $43/MWh.

Q: What is an appropriate adjustment to Pepco's claimed DP avoided energy benefit, which as you point out should mostly be treated as energy revenue?

A: The DP energy savings and price should be reduced to be consistent with the 2015 actuals, plus escalation. This results in a $1.3 M reduction in benefits.

C. Energy Price Mitigation

Q. How does PEPCO estimate the energy-price mitigation resulting from reductions in energy consumption?

A: Pepco estimates the energy-price mitigation by regressing the percentage change in hourly real-time prices as a function of the percentage change in Maryland load, using data from 2013 through early 2015. The price variable was computed from a load-weighted average of the hourly zonal energy prices in the four load zones that cover parts of Maryland. The load variable was computed from the sum of hourly load in the Maryland portion of each of the four zones. The load-weighting calculations were performed for each of four time periods (peak and off-peak, summer and winter). These Maryland loads and load-weighted prices were then normalized (apparently so that the average normalized load and price in each of the four periods were each 1.0). The resulting regression coefficients and the goodness-of-fit measures are shown in Table 11. The coefficients represent Pepco's estimate of the percentage change in weighted price per 1% change in Maryland load.[39]

[39] Since Pepco Maryland is about 25% of Maryland load, so the equivalent price change for a 1% change in Pepco Maryland load would be about 0.4% in the summer periods, 1.1% in the non-summer peak, and 0.8% in the non-summer off-peak. Averaged over the year, the effect of a 1% reduction in Maryland Pepco load would be about 0.9% and 0.6% off-peak.

Table 11: Pepco Regression Results for Energy Price Mitigation (%Δ price per %Δ load)

	Coefficient	R^2	Adjusted R^2
Summer peak	1.667	0.069	0.069
Summer off-peak	1.613	0.102	0.102
Non-Summer peak	4.579	0.125	0.125
Non-Summer off-peak	3.130	0.138	0.138

Pepco then converts these coefficients into a reduction in Maryland energy bills per megawatt-hour of load reduction. That computation should involve multiplying the coefficient times the average energy price, dividing by Maryland load, and multiplying by Maryland energy purchases from the market.[40] Pepco appears to have done something along those lines, although there is no indication that Pepco recognized the energy that Maryland customers obtain from contracts. In Attachment C, Pepco's estimate of the energy-price mitigation effect is approximately $1.42 per MWh of savings.[41] Pepco seems to have computed this value for one year but applies it for the entire benefit analysis, with most of the benefits in 2016 through 2023.

Q: What problems have you identified in PEPCO's analysis of energy price mitigation?

A: I have identified several problems with Pepco's estimation of energy price mitigation, other than the unnecessary complex and contradictory documentation.

- Pepco assumed that observed changes in prices were driven exclusively by Maryland loads.
- Pepco assumed that the effect of load in any part of Maryland had the same effect on prices in all parts of Maryland.

[40] Not all Maryland energy is purchased at short-term market prices, so the price reductions would not affect all usage, especially in the short term.

[41] Pepco accidentally used the $2/MWh environmental price for the non-residential CVR benefit, rather than the $1.42/MWh energy price-mitigation value. I corrected this error.

- Pepco failed to reflect changing energy prices in estimating the effect of a percentage change in price.

Q: How did Pepco determine the effect of Pepco load on the price in each zone?

A: Pepco's evidence on this point is ambiguous. According to the work process flow provided in Staff DR 6-1 Attachment M, a regression was run for each period and each utility zone. The regression results provided in OPC DR 8-21, Attachment G, indicate regressions were run for each period only for the weighted prices. The documentation in Staff DR 6-1, Attachment M, also indicates that only one set of regressions was run for each time period. It does not appear that Pepco determined the effect of reducing Pepco load on the price in each zone.

Q: Is there any justification for Pepco's assumption that only Maryland load affects Maryland prices?

A: No. At the simplest level, Pepco's exclusion of load in the other parts of the Pepco, Delmarva and AP zones strains credulity. There is only one Pepco zone, and load in DC affects the Pepco zonal energy price as much as load in Pepco's Maryland territory does. Yet Pepco ignores DC load. There is only one Delmarva zone, and Delaware load affects the Delmarva zonal energy price as much as load in Delmarva's Maryland territory does. Yet Pepco ignores Delaware load. There is only one Allegheny zone, and load in Pennsylvania, Virginia, or West Virginia affects the AP zonal energy price as much as load in AP's Maryland territory does. Yet Pepco ignores AP's Pennsylvania, Virginia, and West Virginia loads.

At a broader level, Pepco's assumption that other zones do not affect prices in the load zones that cover portions of Maryland is also implausible. The Allegheny zone appears to be at least as well connected to PJM's Ohio and Pennsylvania utilities as to Pepco and BGE, and Delmarva and AP are connected only through western MAAC utilities. Since most transmission connections between Delmarva and Pepco run through WMAAC (especially PPL and MetEd), it seems obvious that load in WMAAC is at least as important in determining Delmarva prices as is Pepco load.

Q: Is there any justification for assuming that load in any part of Maryland has the same effect on prices in all the Maryland zones?

A: No.

Q: Have you conducted any additional analysis of the effects of Pepco load on energy prices in the four Maryland zones?

A: Yes. I have run a number of other regressions, using various combinations of PJM, MAAC, WMAAC, and local zones. The best fits I found, which are summarized in Table 9, are more realistic than the method employed by Pepco because they reflect loads other than Pepco MD, and recognize the effect of wider areas. The statistical tests for the equations in Table 12 are generally better than the complicated and questionable results provided by Pepco's aggregation of loads, regression of load weighted pricing periods, and averaging of residual sales. The coefficients make much more sense, and the equations fit the data much better.

Table 12: Improved Regressions for Maryland Load Zones
% change in zonal price per % change in load

	Load Zones						
Price Zone	**BGE+ Pepco +DPL**	**AP**	**WMAAC +AP**	**PJM - ComEd**	**R^2**	**Pepco as % of Variable**	**% price Δ per Pepco % load Δ**
On-peak							
BGE	**1.46**	1.58			0.48	29%	0.4234
Pepco	**1.46**	1.60			0.48	29%	0.4234
DPL	**1.10**		2.10		0.51	29%	0.3190
AP				**2.81**	0.42	0.5%	0.0146
Off-peak							
BGE	**1.08**	1.00			0.48	29%	0.3132
Pepco	**1.11**	0.96			0.48	29%	0.3219
DPL	**1.37**		0.53		0.48	29%	0.3973
AP				**1.67**	0.40	0.5%	0.0087

Averaged over the four load zones, weighted by the energy load in each zone, these coefficients are 0.36 on peak and 0.28 off-peak, about 40% of Pepco's estimates.

Q: What are the implications of these results for Pepco's estimates of energy price mitigation?

A: This improvement would reduce the energy price mitigation by 60%, or almost $1 million.

IX. Summary of Corrections

Q: Please list the errors you have found in Pepco's analysis of system benefits from the load reductions that Pepco attributes to smart-meter-enabled programs.

A: In Sections III through VIII, I identified the following errors:

- Avoided Capacity Cost
  - The load forecast from which Pepco estimates savings is outdated.
  - The capacity obligation for Pepco customers will not be significantly reduced by the DP load reductions, because they affect very few of the thousands of summer days used in the PJM peak forecasts, and the affected days are not well chosen to change PJM's load forecasts.
  - Pepco overstates the DP load reductions, by ignoring customers whose load increased on ESDs and hence not offsetting reductions that would have occurred without the program with increases that occurred even with the program.
  - The load reductions from CVR and EMT would tend to affect capacity obligation much more slowly than Pepco assumes, with only about 30%

of the 2013–2015 reductions affecting the 2016 forecasts that will determine Pepco's 2019/20 obligations.

- Capacity Price Mitigation
  - The load forecasts from which Pepco estimates the energy affected by price mitigation are outdated.
  - While capacity bid into the BRA from the DP program has and will tend to reduce capacity prices through 2020/21, it will also increase capacity obligations.
  - Load reductions from the DP program that are not bid into the BRA have negligible effects on market price, due to their rarity and timing.
  - Pepco overstates the DP load reductions, by ignoring the customers who increase load and the customers who would have decreased load even without the program.
  - The load reductions from EMT would reduce capacity prices much less than Pepco assumes.
  - Pepco's estimate of the effect of load reductions on capacity prices is grossly overstated.
  - Historical experience suggests that capacity prices in the Delmarva service territory will often be unaffected by supply and demand in the Pepco zone.
  - Pepco incorrectly assumes that its demand response resources have always reduced prices for premium resources.
- Transmission and Distribution Benefits
  - Pepco improperly combines a nominally levelized T&D carrying charge (which includes the effect of inflation over 44 years) and inflation of the resulting annualized costs.

        - None of the T&D investment modeled by Pepco has been deferred through the present time, and little or none appears to be avoidable in Pepco's projections though 2020.
        - The DP load reductions, given their rarity and timing, are unlikely to affect transmission or distribution investment, given the variability in the timing of peaks on T&D equipment. The peak loads on the transmission lines have not fallen on the PESC hours.
- Energy Revenue
    - Pepco overstates the price of energy during its PESC hours.
- Energy Savings
    - Pepco overstates the DP benefits, by including randomly-occurring load reductions.
    - Pepco failed to reflect the cost of buying energy savings through the PESC rebates.
- Energy Price Mitigation
    - Pepco incorrectly assumed that energy prices for each of the Maryland zones is driven solely by Maryland load, ignoring the influence of the rest of the Pepco, DPL and AP zones, and other parts of PJM, and thus overstating the effect of Pepco load.
    - Pepco overstates DP savings (and hence the effect on prices) by including random load reductions (but not random load increases) in the PESC hours.

Q: Please summarize the system benefits with your adjustments.

A:

Table 13 updates Table 2 to reflect the adjustments I made above.

Table 13: Adjusted System Benefits, $M of 2015 PV

Benefit Category	CVR	DP & EWR	EMT	Total
Capacity Price Mitigation	$1.3	$14.6	$3.2	$19.0
Energy Price Mitigation	$0.2	$0	$0.2	$0.4
Capacity Revenue	—	$33.1	—	$33.1
Energy Revenue		$0.1	—	$0.1
Avoided Capacity	$2.3	—	$6.3	$8.5
Avoided Energy	$47.8	$0.1	$57.1	$104.9
Reduction in Air Emissions	$1.5	$0	$1.8	$3.4
Avoided Transmission Capital Recovery	$0.4	—	$2.3	$2.7
Avoided Distribution Capital Recovery	$0.7	—	$1.5	$2.2
Total	$54.2	$47.8	$72.3	$174.3

For the purposes of this summary, I have accepted Pepco's assumptions about the percentage reduction in energy and peak loads attributable to the effect of the smart meters on the EMT and CVR programs. If these savings are not realistic or could have been achieved without the smart meters, the EMT and CVR column should be reduced or eliminated. Mr. Chang adjusts the these savings in his testimony and also reflects the DP rebates, which are appropriately treated as a program cost.

Q: Does this conclude your direct testimony?

A: Yes, at this time. As additional data become available from Pepco, I may need to update this testimony.

Exhibit PLC-1

PAUL L. CHERNICK

Resource Insight, Inc.
5 Water Street
Arlington, Massachusetts 02476

SUMMARY OF PROFESSIONAL EXPERIENCE

1986–Present **President, Resource Insight, Inc.** Consults and testifies in utility and insurance economics. Reviews utility supply-planning processes and outcomes: assesses prudence of prior power planning investment decisions, identifies excess generating capacity, analyzes effects of power-pool-pricing rules on equity and utility incentives. Reviews electric-utility rate design. Estimates magnitude and cost of future load growth. Designs and evaluates conservation programs for electric, natural-gas, and water utilities, including hook-up charges and conservation cost recovery mechanisms. Determines avoided costs due to cogenerators. Evaluates cogeneration rate risk. Negotiates cogeneration contracts. Reviews management and pricing of district heating systems. Determines fair profit margins for automobile and workers' compensation insurance lines, incorporating reward for risk, return on investments, and tax effects. Determines profitability of transportation services. Advises regulatory commissions in least-cost planning, rate design, and cost allocation.

1981–86 **Research Associate, Analysis and Inference, Inc.** (Consultant, 1980–81). Researched, advised, and testified in various aspects of utility and insurance regulation. Designed self-insurance pool for nuclear decommissioning; estimated probability and cost of insurable events, and rate levels; assessed alternative rate designs. Projected nuclear power plant construction, operation, and decommissioning costs. Assessed reasonableness of earlier estimates of nuclear power plant construction schedules and costs. Reviewed prudence of utility construction decisions. Consulted on utility rate-design issues, including small-power-producer rates; retail natural-gas rates; public-agency electric rates, and comprehensive electric-rate design for a regional power agency. Developed electricity cost allocations between customer classes. Reviewed district-heating-system efficiency. Proposed power-plant performance standards. Analyzed auto-insurance profit requirements. Designed utility-financed, decentralized conservation program. Analyzed cost-effectiveness of transmission lines.

1977–81 **Utility Rate Analyst, Massachusetts Attorney General.** Analyzed utility filings and prepared alternative proposals. Participated in rate negotiations, discovery, cross-examination, and briefing. Provided extensive expert testimony before various regulatory agencies. Topics included demand forecasting, rate design, marginal costs, time-of-use rates, reliability issues, power-pool operations, nuclear-power cost projections, power-plant cost-benefit analysis, energy conservation, and alternative-energy development.

EDUCATION

SM, Technology and Policy Program, Massachusetts Institute of Technology, February 1978.

SB, Civil Engineering Department, Massachusetts Institute of Technology, June 1974.

HONORS

Chi Epsilon (Civil Engineering)

Tau Beta Pi (Engineering)

Sigma Xi (Research)

Institute Award, Institute of Public Utilities, 1981.

PUBLICATIONS

"Price Effects as a Benefit of Energy-Efficiency Programs" (with John Plunkett), *2014 ACEEE Summer Study on Energy Efficiency in Buildings* (5) 57–5-69. 2014.

"Environmental Regulation in the Changing Electric-Utility Industry" (with Rachel Brailove), *International Association for Energy Economics Seventeenth Annual North American Conference* (96–105). Cleveland, Ohio: USAEE. 1996.

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"The Transfer Loss is All Transfer, No Loss" (with Jonathan Wallach), The *Electricity Journal* 6:6 (July 1993).

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"ESCos or Utility Programs: Which Are More Likely to Succeed?" (with Sabrina Birner), *The Electricity Journal* 5:2, March 1992.

“Determining the Marginal Value of Greenhouse Gas Emissions” (with Jill Schoenberg), *Energy Developments in the 1990s: Challenges Facing Global/Pacific Markets, Vol. II,* July 1991.

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“Accounting for Externalities” (with Emily Caverhill). *Public Utilities Fortnightly* 127(5), March 1 1991.

“Methods of Valuing Environmental Externalities” (with Emily Caverhill), *The Electricity Journal* 4(2), March 1991.

“The Valuation of Environmental Externalities in Energy Conservation Planning” (with Emily Caverhill), *Energy Efficiency and the Environment: Forging the Link*. American Council for an Energy-Efficient Economy; Washington: 1991.

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“Externalities and Your Electric Bill,” *The Electricity Journal*, October 1990, p. 64.

“Monetizing Externalities in Utility Regulations: The Role of Control Costs” (with Emily Caverhill) *Proceedings from the NARUC National Conference on Environmental Externalities*, October 1990.

“Monetizing Environmental Externalities in Utility Planning” (with Emily Caverhill), in *Proceedings from the NARUC Biennial Regulatory Information Conference*, September 1990.

“Analysis of Residential Fuel Switching as an Electric Conservation Option” (with Eric Espenhorst and Ian Goodman), in *Proceedings from the NARUC Biennial Regulatory Information Conference*, September 1990.

“A Utility Planner’s Checklist for Least-Cost Efficiency Investment” (with John Plunkett) in *Proceedings from the NARUC Biennial Regulatory Information Conference*, September 1990.

Environmental Costs of Electricity (with Richard Ottinger et al.). Oceana; Dobbs Ferry, New York: September 1990.

“Demand-Side Bidding: A Viable Least-Cost Resource Strategy” (with John Plunkett and Jonathan Wallach), in *Proceedings from the NARUC Biennial Regulatory Information Conference*, September 1990.

“Incorporating Environmental Externalities in Evaluation of District Heating Options” (with Emily Caverhill), *Proceedings from the International District Heating and Cooling Association 81st Annual Conference*, June 1990.

“A Utility Planner’s Checklist for Least-Cost Efficiency Investment,” (with John Plunkett), *Proceedings from the Canadian Electrical Association Demand-Side Management Conference,* June 1990.

“Incorporating Environmental Externalities in Utility Planning” (with Emily Caverhill), *Canadian Electrical Association Demand Side Management Conference*, May 1990.

“Is Least-Cost Planning for Gas Utilities the Same as Least-Cost Planning for Electric Utilities?” in *Proceedings of the NARUC Second Annual Conference on Least-Cost Planning*, September 10–13 1989.

“Conservation and Cost-Benefit Issues Involved in Least-Cost Planning for Gas Utilities,” in *Least Cost Planning and Gas Utilities: Balancing Theories with Realities*, Seminar proceedings from the District of Columbia Natural Gas Seminar, May 23 1989.

“The Role of Revenue Losses in Evaluating Demand-Side Resources: An Economic Re-Appraisal” (with John Plunkett), *Summer Study on Energy Efficiency in Buildings, 1988*, American Council for an Energy Efficient Economy, 1988.

“Quantifying the Economic Benefits of Risk Reduction: Solar Energy Supply Versus Fossil Fuels,” in *Proceedings of the 1988 Annual Meeting of the American Solar Energy Society*, American Solar Energy Society, Inc., 1988, pp. 553–557.

“Capital Minimization: Salvation or Suicide?,” in I. C. Bupp, ed., *The New Electric Power Business*, Cambridge Energy Research Associates, 1987, pp. 63–72.

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“Power Plant Performance Standards: Some Introductory Principles,” *Public Utilities Fortnightly*, April 18 1985, pp. 29–33.

“Opening the Utility Market to Conservation: A Competitive Approach,” *Energy Industries in Transition, 1985–2000,* Proceedings of the Sixth Annual North American Meeting of the International Association of Energy Economists, San Francisco, California, November 1984, pp. 1133–1145.

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"Comments on Nova Scotia Power Inc.'s Proposed Capital Expenditure Justification Criteria." 2013. Filed by the Nova Scotia Small Business Advocate in N.S. UARB Matter No. 05355.

"Avoided Energy Supply Costs in New England: 2013 Report" (with Rick Hornby, David White, John Rosenkranz, Ron Denhardt, Elizabeth Stanton, Jason Gifford, Bob Grace, Max Chang, Patrick Luckow, Thomas Vitolo, Patrick Knight, Ben Griffiths, and Bruce Biewald). 2011. Northborough, Mass.: Avoided-Energy-Supply-Component Study Group, c/o National Grid Company.

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Engineers environmental assessment in Department of the Army Environmental Assessment and Statement of Finding for Permit Application SAJ-2010-02881.

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"Avoided Energy Supply Costs in New England: 2011 Report" (with Rick Hornby, Carl Swanson, David White, Jason Gifford, Max Chang, Nicole Hughes, Matthew Wittenstein, Rachel Wilson, and Bruce Biewald). 2011. Northborough, Mass.: Avoided-Energy-Supply-Component Study Group, c/o National Grid Company.

"State of Ohio Energy-Efficiency Technical-Reference Manual Including Predetermined Savings Values and Protocols for Determining Energy and Demand Savings" (with others). 2010. Burlington, Vt.: Vermont Energy Investment Corporation.

"Avoided Energy Supply Costs in New England: 2011 Report" (with Rick Hornby, Carl Swanson, David White, Ian Goodman, Bob Grace, Bruce Biewald, Ben Warfield, Jason Gifford, and Max Chang). 2009. Northborough, Mass.: Avoided-Energy-Supply-Component Study Group, c/o National Grid Company.

"Green Resource Portfolios: Development, Integration, and Evaluation" (with Jonathan Wallach and Richard Mazzini). 2008. Report to the Green Energy Coalition presented as evidence in Ont. Energy Board EB 2007-0707.

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"Integrated Portfolio Management in a Restructured Supply Market" (with Jonathan Wallach, William Steinhurst, Tim Woolf, Anna Sommers, and Kenji Takahashi). 2006. Columbus, Ohio: Office of the Ohio Consumers' Counsel.

"Natural Gas Efficiency Resource Development Potential in New York" (with Phillip Mosenthal, R. Neal Elliott, Dan York, Chris Neme, and Kevin Petak). 2006. Albany, N.Y.; New York State Energy Research and Development Authority.

"Natural Gas Efficiency Resource Development Potential in Con Edison Service Territory" (with Phillip Mosenthal, Jonathan Kleinman, R. Neal Elliott, Dan York, Chris Neme, and Kevin Petak. 2006. Albany, N.Y.; New York State Energy Research and Development Authority.

"Evaluation and Cost Effectiveness" (principal author), Ch. 14 of "California Evaluation Framework" Prepared for California utilities as required by the California Public Utilities Commission. 2004.

"Energy Plan for the City of New York" (with Jonathan Wallach, Susan Geller, Brian Tracey, Adam Auster, and Peter Lanzalotta). 2003. New York: New York City Economic Development Corporation.

"Updated Avoided Energy Supply Costs for Demand-Side Screening in New England" (with Susan Geller, Bruce Biewald, and David White). 2001. Northborough, Mass.: Avoided-Energy-Supply-Component Study Group, c/o New England Power Supply Company.

"Review and Critique of the Western Division Load-Pocket Study of Orange and Rockland Utilities, Inc." (with John Plunkett, Philip Mosenthal, Robert Wichert, and Robert Rose). 1999. White Plains, N.Y.: Pace University School of Law Center for Environmental Studies.

"Avoided Energy Supply Costs for Demand-Side Management in Massachusetts" (with Rachel Brailove, Susan Geller, Bruce Biewald, and David White). 1999. Northborough, Mass.: Avoided-Energy-Supply-Component Study Group, c/o New England Power Supply Company.

"Performance-based Regulation in a Restructured Utility Industry" (with Bruce Biewald, Tim Woolf, Peter Bradford, Susan Geller, and Jerrold Oppenheim). 1997. Washington: NARUC.

"Distributed Integrated-Resource-Planning Guidelines." 1997. Appendix 4 of "The Power to Save: A Plan to Transform Vermont's Energy-Efficiency Markets," submitted to the Vt. PSB in Docket No. 5854. Montpelier: Vermont DPS.

"Restructuring the Electric Utilities of Maryland: Protecting and Advancing Consumer Interests" (with Jonathan Wallach, Susan Geller, John Plunkett, Roger Colton, Peter Bradford, Bruce Biewald, and David Wise). 1997. Baltimore, Maryland: Maryland Office of People's Counsel.

"Comments of the New Hampshire Office of Consumer Advocate on Restructuring New Hampshire's Electric-Utility Industry" (with Bruce Biewald and Jonathan Wallach). 1996. Concord, N.H.: NH OCA.

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"Estimation of the Costs Avoided by Potential Demand-Management Activities of Ontario Hydro," December 1992.

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Environmental Externalities Valuation and Ontario Hydro's Resource Planning (with E. Caverhill and R. Brailove), 3 vols.; prepared for the Coalition of Environmental Groups for a Sustainable Energy Future, October 1992.

"Review of Jersey Central Power & Light's 1992 DSM Plan and the Demand-Side Management Rules" (with Jonathan Wallach et al.); Report to the New Jersey Department of Public Advocate, June 1992.

"The AGREA Project Critique of Externality Valuation: A Brief Rebuttal," March 1992.

"The Potential Economic Benefits of Regulatory NO_X Valuation for Clean Air Act Ozone Compliance in Massachusetts," March 1992.

"Initial Review of Ontario Hydro's Demand-Supply Plan Update" (with David Argue et al.), February 1992.

"Report on the Adequacy of Ontario Hydro's Estimates of Externality Costs Associated with Electricity Exports" (with Emily Caverhill), January 1991.

"Comments on the 1991–1992 Annual and Long Range Demand-Side-Management Plans of the Major Electric Utilities," (with John Plunkett et al.), September 1990. Filed in NY PSC Case No. 28223 in re New York utilities' DSM plans.

"Power by Efficiency: An Assessment of Improving Electrical Efficiency to Meet Jamaica's Power Needs," (with Conservation Law Foundation, et al.), June 1990.

"Analysis of Fuel Substitution as an Electric Conservation Option," (with Ian Goodman and Eric Espenhorst), Boston Gas Company, December 22 1989.

"The Development of Consistent Estimates of Avoided Costs for Boston Gas Company, Boston Edison Company, and Massachusetts Electric Company" (with Eric Espenhorst), Boston Gas Company, December 22 1989.

"The Valuation of Externalities from Energy Production, Delivery, and Use: Fall 1989 Update" (with Emily Caverhill), Boston Gas Company, December 22 1989.

"Conservation Potential in the State of Minnesota," (with Ian Goodman) Minnesota Department of Public Service, June 16 1988.

"Review of NEPOOL Performance Incentive Program," Massachusetts Energy Facilities Siting Council, April 12 1988.

"Application of the DPU's Used-and-Useful Standard to Pilgrim 1" (With C. Wills and M. Meyer), Massachusetts Executive Office of Energy Resources, October 1987.

"Constructing a Supply Curve for Conservation: An Initial Examination of Issues and Methods," Massachusetts Energy Facilities Siting Council, June 1985.

“Final Report: Rate Design Analysis,” Pacific Northwest Electric Power and Conservation Planning Council, December 18 1981.

PRESENTATIONS

“Residential Demand Charges - Load Effects, Fairness & Rate Design Implications.” Web seminar sponsored by the NixTheFix Forum. September 2015.

“The Value of Demand Reduction Induced Price Effects.” With Chris Neme. Web seminar sponsored by the Regulatory Assistance Project. March 2015.

“Adding Transmission into New York City: Needs, Benefits, and Obstacles.” Presentation to FERC and the New York ISO on behalf of the City of New York. October 2004.

“Plugging Into a Municipal Light Plant.” With Peter Enrich and Ken Barna. Panel presentation as part of the 2004 Annual Meeting of the Massachusetts Municipal Association. January 2004.

“Distributed Utility Planning.” With Steve Litkovitz. Presentation to the Vermont Distributed-Utility-Planning Collaborative. November 1999.

“The Economic and Environmental Benefits of Gas IRP: FERC 636 and Beyond.” Presentation as part of the Ohio Office of Energy Efficiency’s seminar, “Gas Utility Integrated Resource Planning,” April 1994.

“Cost Recovery and Utility Incentives.” Day-long presentation as part of the Demand-Side-Management Training Institute’s workshop, “DSM for Public Interest Groups,” October 1993.

“Cost Allocation for Utility Ratemaking.” With Susan Geller. Day-long workshop for the staff of the Connecticut Department of Public Utility Control, October 1993.

“Comparing and Integrating DSM with Supply.” Day-long presentation as part of the Demand-Side-Management Training Institute’s workshop, “DSM for Public Interest Groups,” October 1993.

“DSM Cost Recovery and Rate Impacts.” Presentation as part of “Effective DSM Collaborative Processes,” a week-long training session for Ohio DSM advocates sponsored by the Ohio Office of Energy Efficiency, August 1993.

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“Environmental Externalities: Current Approaches and Potential Implications for District Heating and Cooling” (with R. Brailove), International District Heating and Cooling Association 84th Annual Conference. June 1993.

“Using the Costs of Required Controls to Incorporate the Costs of Environmental Externalities in Non-Environmental Decision-Making.” Presentation at the American Planning

Association 1992 National Planning Conference; presentation cosponsored by the Edison Electric Institute. May 1992.

“Cost Recovery and Decoupling” and “The Clean Air Act and Externalities in Utility Resource Planning” panels (session leader), DSM Advocacy Workshop. April 15 1992.

“Overview of Integrated Resources Planning Procedures in South Carolina and Critique of South Carolina Demand Side Management Programs,” Energy Planning Workshops; Columbia, S.C. October 21 1991.

“Least Cost Planning and Gas Utilities.” Conservation Law Foundation Utility Energy Efficiency Advocacy Workshop; Boston, February 28 1991.

“Least-Cost Planning in a Multi-Fuel Context.” NARUC Forum on Gas Integrated Resource Planning; Washington, D.C., February 24 1991.

“Accounting for Externalities: Why, Which and How?” Understanding Massachusetts’ New Integrated Resource Management Rules. Needham, Massachusetts, November 9 1990.

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“Conservation and Load Management for Natural Gas Utilities,” Massachusetts Natural Gas Council; Newton, Massachusetts. April 3 1989.

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“Assessment and Valuation of External Environmental Damages.” New England Utility Rate Forum. Plymouth, Massachusetts, October 11 1985; “Lessons from Massachusetts on Long Term Rates for QFs”.

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“Power Plant Performance.,” National Association of State Utility Consumer Advocates; Williamstown, Massachusetts. August 13 1984.

“Utility Rate Shock,” National Conference of State Legislatures; Boston, Massachusetts, August 6 1984.

“Review and Modification of Regulatory and Rate Making Policy,” National Governors’ Association Working Group on Nuclear Power Cost Overruns; Washington, D.C., June 20 1984.

"Review and Modification of Regulatory and Rate Making Policy," Annual Meeting of the American Association for the Advancement of Science, Session on Monitoring for Risk Management; Detroit, Michigan, May 27 1983.

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Connecticut Department of Public Utility Control, Docket No. 87-07-01, Phase 2; Rate design and cost allocations. March 1988 to June 1989.

Austin City Council, Austin Energy Rates, March to June 2012.

EXPERT TESTIMONY

1. **Mass. EFSC** 78-12/MDPU 19494, Phase I; Boston Edison 1978 forecast; Massachusetts Attorney General. June 12 1978.

   Appliance penetration projections, price elasticity, econometric commercial forecast, peak demand forecast. Joint testimony with Susan C. Geller.

2. **Mass. EFSC** 78-17, Northeast Utilities 1978 forecast; Massachusetts Attorney General. September 29 1978.

   Specification of economic/demographic and industrial models, appliance efficiency, commercial model structure and estimation.

3. **Mass. EFSC** 78-33, Eastern Utilities Associates 1978 forecast; Massachusetts Attorney General. November 27 1978.

   Household size, appliance efficiency, appliance penetration, price elasticity, commercial forecast, industrial trending, peak demand forecast.

4. **Mass. DPU** 19494, Phase II; Boston Edison Company construction program; Massachusetts Attorney General. April 1 1979.

   Review of numerous aspects of the 1978 demand forecasts of nine New England electric utilities, constituting 92% of projected regional demand growth, and of the NEPOOL demand forecast. Joint testimony with Susan Geller.

5. **Mass. DPU** 19494, Phase II; Boston Edison Company construction program; Massachusetts Attorney General. April 1 1979.

   Reliability, capacity planning, capability responsibility allocation, customer generation, co-generation rates, reserve margins, operating reserve allocation. Joint testimony with S. Finger.

6. **U.S. ASLB** NRC 50-471, Pilgrim Unit 2; Commonwealth of Massachusetts. June 29 1979.

   Review of the Oak Ridge National Laboratory and NEPOOL demand forecast models; cost-effectiveness of oil displacement; nuclear economics. Joint testimony with Susan Geller.

7. **Mass. DPU** 19845, Boston Edison time-of-use-rate case; Massachusetts Attorney General. December 4 1979. (Not presented)

   Critique of utility marginal cost study and proposed rates; principles of marginal cost principles, cost derivation, and rate design; options for reconciling costs and revenues. Joint testimony with Susan Geller.

8. **Mass. DPU** 20055, petition of Eastern Utilities Associates, New Bedford G. & E., and Fitchburg G. & E. to purchase additional shares of Seabrook Nuclear Plant; Massachusetts Attorney General. January 23 1980.

   Review of demand forecasts of three utilities purchasing Seabrook shares; Seabrook power costs, including construction cost, completion date, capacity factor, O&M expenses, interim replacements, reserves and uncertainties; alternative energy sources, including conservation, cogeneration, rate reform, solar, wood and coal conversion.

9. **Mass. DPU** 20248, petition of Massachusetts Municipal Wholesale Electric Company to purchase additional share of Seabrook Nuclear Plant; Massachusetts Attorney General. June 2 1980.

   Nuclear power costs; update and extension of MDPU 20055 testimony.

10. **Mass. DPU** 200, Massachusetts Electric Company rate case; Massachusetts Attorney General. June 16 1980.

    Rate design; declining blocks, promotional rates, alternative energy, demand charges, demand ratchets; conservation: master metering, storage heating, efficiency standards, restricting resistance heating.

11. **Mass. EFSC** 79-33, Eastern Utilities Associates 1979 forecast; Massachusetts Attorney General. July 16 1980.

    Customer projections, consistency issues, appliance efficiency, new appliance types, commercial specifications, industrial data manipulation and trending, sales and resale.

12. **Mass. DPU** 243, Eastern Edison Company rate case; Massachusetts Attorney General. August 19 1980.

    Rate design: declining blocks, promotional rates, alternative energy, master metering.

13. **Texas** **PUC** 3298, Gulf States Utilities rate case; East Texas Legal Services. August 25 1980.

    Inter-class revenue allocations, including production plant in-service, O&M, CWIP, nuclear fuel in progress, amortization of canceled plant residential rate design; interruptible rates; off-peak rates. Joint testimony with M. B. Meyer.

14. **Mass.** **EFSC** 79-1, Massachusetts Municipal Wholesale Electric Company Forecast; Massachusetts Attorney General. November 5 1980.

    Cost comparison methodology; nuclear cost estimates; cost of conservation, cogeneration, and solar.

15. **Mass.** **DPU** 472, recovery of residential conservation-service expenses; Massachusetts Attorney General. December 12 1980.

    Conservation as an energy source; advantages of per-kWh allocation over per-customer-month allocation.

16. **Mass.** **DPU** 535; regulations to carry out Section 210 of PURPA; Massachusetts Attorney General. January 26 1981 and February 13 1981.

    Filing requirements, certification, qualifying-facility status, extent of coverage, review of contracts; energy rates; capacity rates; extra benefits of qualifying facilities in specific areas; wheeling; standardization of fees and charges.

17. **Mass.** **EFSC** 80-17, Northeast Utilities 1980 forecast; Massachusetts Attorney General. March 12 1981 (not presented).

    Specification process, employment, electric heating promotion and penetration, commercial sales model, industrial model specification, documentation of price forecasts and wholesale forecast.

18. **Mass.** **DPU** 558, Western Massachusetts Electric Company rate case; Massachusetts Attorney General. May 1981.

    Rate design including declining blocks, marginal cost conservation impacts, and promotional rates. Conservation, including terms and conditions limiting renewable, cogeneration, small power production; scope of current conservation program; efficient insulation levels; additional conservation opportunities.

19. **Mass.** **DPU** 1048, Boston Edison plant performance standards; Massachusetts Attorney General. May 7 1982.

    Critique of company approach, data, and statistical analysis; description of comparative and absolute approaches to standard-setting; proposals for standards and reporting requirements.

20. **D.C.** **PSC** FC785, Potomac Electric Power rate case; D.C. People's Counsel. July 29 1982.

Inter-class revenue allocations, including generation, transmission, and distribution plant classification; fuel and O&M classification; distribution and service allocators. Marginal cost estimation, including losses.

21. **N.H. PSC** DE1-312, Public Service of New Hampshire supply and demand; Conservation Law Foundation et al. October 8 1982.

    Conservation program design, ratemaking, and effectiveness. Cost of power from Seabrook nuclear plant, including construction cost and duration, capacity factor, O&M, replacements, insurance, and decommissioning.

22. **Mass. Division of Insurance,** hearing to fix and establish 1983 automobile insurance rates; Massachusetts Attorney General. October 1982.

    Profit margin calculations, including methodology, interest rates, surplus flow, tax flows, tax rates, and risk premium.

23. **Ill. CC** 82-0026, Commonwealth Edison rate case; Illinois Attorney General. October 15 1982.

    Review of Cost-Benefit Analysis for nuclear plant. Nuclear cost parameters (construction cost, O&M, capital additions, useful like, capacity factor), risks, discount rates, evaluation techniques.

24. **N.M. PSC** 1794, Public Service of New Mexico application for certification; New Mexico Attorney General. May 10 1983.

    Review of Cost-Benefit Analysis for transmission line. Review of electricity price forecast, nuclear capacity factors, load forecast. Critique of company ratemaking proposals; development of alternative ratemaking proposal.

25. **Conn. DPUC** 830301, United Illuminating rate case; Connecticut Consumers Counsel. June 17 1983.

    Cost of Seabrook nuclear power plants, including construction cost and duration, capacity factor, O&M, capital additions, insurance and decommissioning.

26. **Mass. DPU** 1509, Boston Edison plant performance standards; Massachusetts Attorney General. July 15 1983.

    Critique of company approach and statistical analysis; regression model of nuclear capacity factor; proposals for standards and for standard-setting methodologies.

27. **Mass. Division of Insurance,** hearing to fix and establish 1984 automobile-insurance rates; Massachusetts Attorney General. October 1983.

    Profit margin calculations, including methodology, interest rates.

28. **Conn. DPUC** 83-07-15, Connecticut Light and Power rate case; Alloy Foundry. October 3 1983.

Industrial rate design. Marginal and embedded costs; classification of generation, transmission, and distribution expenses; demand versus energy charges.

29. **Mass.** **EFSC** 83-24, New England Electric System forecast of electric resources and requirements; Massachusetts Attorney General. November 14 1983, Rebuttal, February 2 1984.

    Need for transmission line. Status of supply plan, especially Seabrook 2. Review of interconnection requirements. Analysis of cost-effectiveness for power transfer, line losses, generation assumptions.

30. **Mich.** **PSC** U-7775, Detroit Edison Fuel Cost Recovery Plan; Public Interest Research Group in Michigan. February 21 1984.

    Review of proposed performance target for new nuclear power plant. Formulation of alternative proposals.

31. **Mass.** **DPU** 84-25, Western Massachusetts Electric Company rate case; Massachusetts Attorney General. April 6 1984.

    Need for Millstone 3. Cost of completing and operating unit, cost-effectiveness compared to alternatives, and its effect on rates. Equity and incentive problems created by CWIP. Design of Millstone 3 phase-in proposals to protect ratepayers: limitation of base-rate treatment to fuel savings benefit of unit.

32. **Mass.** **DPU** 84-49 and 84-50, Fitchburg Gas & Electric financing case; Massachusetts Attorney General. April 13 1984.

    Cost of completing and operating Seabrook nuclear units. Probability of completing Seabrook 2. Recommendations regarding FG&E and MDPU actions with respect to Seabrook.

33. **Mich.** **PSC** U-7785, Consumers Power fuel-cost-recovery plan; Public Interest Research Group in Michigan. April 16 1984.

    Review of proposed performance targets for two existing and two new nuclear power plants. Formulation of alternative policy.

34. **FERC** ER81-749-000 and ER82-325-000, Montaup Electric rate cases; Massachusetts Attorney General. April 27 1984.

    Prudence of Montaup and Boston Edison in decisions regarding Pilgrim 2 construction: Montaup's decision to participate, the Utilities' failure to review their earlier analyses and assumptions, Montaup's failure to question Edison's decisions, and the utilities' delay in canceling the unit.

35. **Maine** **PUC** 84-113, Seabrook-1 investigation; Maine Public Advocate. September 13 1984.

Cost of completing and operating Seabrook Unit 1. Probability of completing Seabrook 1. Comparison of Seabrook to alternatives. Rate effects. Recommendations regarding utility and PUC actions with respect to Seabrook.

36. **Mass. DPU** 84-145, Fitchburg Gas and Electric rate case; Massachusetts Attorney General. November 6 1984.

Prudence of Fitchburg and Public Service of New Hampshire in decision regarding Seabrook 2 construction: FGE's decision to participate, the utilities' failure to review their earlier analyses and assumptions, FGE's failure to question PSNH's decisions, and utilities' delay in halting construction and canceling the unit. Review of literature, cost and schedule estimate histories, cost-benefit analyses, and financial feasibility.

37. **Penn. PUC** R-842651, Pennsylvania Power and Light rate case; Pennsylvania Consumer Advocate. November 1984.

Need for Susquehanna 2. Cost of operating unit, power output, cost-effectiveness compared to alternatives, and its effect on rates. Design of phase-in and excess capacity proposals to protect ratepayers: limitation of base-rate treatment to fuel savings benefit of unit.

38. **N.H. PSC** 84-200, Seabrook Unit-1 investigation; New Hampshire Public Advocate. November 15 1984.

Cost of completing and operating Seabrook Unit 1. Probability of completing Seabrook 1. Comparison of Seabrook to alternatives. Rate and financial effects.

39. **Mass. Division of Insurance,** hearing to fix and establish 1986 automobile insurance rates; Massachusetts Attorney General. November 1984.

Profit-margin calculations, including methodology and implementation.

40. **Mass. DPU** 84-152, Seabrook Unit 1 investigation; Massachusetts Attorney General. December 12 1984.

Cost of completing and operating Seabrook. Probability of completing Seabrook 1. Seabrook capacity factors.

41. **Maine PUC** 84-120; Central Maine Power rate case; Maine PUC Staff. December 11 1984.

Prudence of Central Maine Power and Boston Edison in decisions regarding Pilgrim 2 construction: CMP's decision to participate, the utilities' failure to review their earlier analyses and assumptions, CMP's failure to question Edison's decisions, and the utilities' delay in canceling the unit. Prudence of CMP in the planning and investment in Sears Island nuclear and coal plants. Review of literature, cost and schedule estimate histories, cost-benefit analyses, and financial feasibility.

42. Maine PUC 84-113, Seabrook 2 investigation; Maine PUC Staff. December 14 1984.

Prudence of Maine utilities and Public Service of New Hampshire in decisions regarding Seabrook 2 construction: decisions to participate and to increase ownership share, the utilities' failure to review their earlier analyses and assumptions, failure to question PSNH's decisions, and the utilities' delay in halting construction and canceling the unit. Review of literature, cost and schedule estimate histories, cost-benefit analyses, and financial feasibility.

43. Mass. DPU 1627, Massachusetts Municipal Wholesale Electric Company financing case; Massachusetts Executive Office of Energy Resources. January 14 1985.

Cost of completing and operating Seabrook nuclear unit 1. Cost of conservation and other alternatives to completing Seabrook. Comparison of Seabrook to alternatives.

44. Vt. PSB 4936, Millstone 3 costs and in-service date; Vermont Department of Public Service. January 21 1985.

Construction schedule and cost of completing Millstone Unit 3.

45. Mass. DPU 84-276, rules governing rates for utility purchases of power from qualifying facilities; Massachusetts Attorney General. March 25 1985 and October 18 1985.

Institutional and technological advantages of Qualifying Facilities. Potential for QF development. Goals of QF rate design. Parity with other power sources. Security requirements. Projecting avoided costs. Capacity credits. Pricing options. Line loss corrections.

46. Mass. DPU 85-121, investigation of the Reading Municipal Light Department; Wilmington (Mass.) Chamber of Commerce. November 12 1985.

Calculation on return on investment for municipal utility. Treatment of depreciation and debt for ratemaking. Geographical discrimination in street-lighting rates. Relative size of voluntary payments to Reading and other towns. Surplus and disinvestment. Revenue allocation.

47. Mass. Division of Insurance, hearing to fix and establish 1986 automobile insurance rates; Massachusetts Attorney General and State Rating Bureau. November 1985.

Profit margin calculations, including methodology, implementation, modeling of investment balances, income, and return to shareholders.

48. N.M. PSC 1833, Phase II; El Paso Electric rate case; New Mexico Attorney General. December 23 1985.

Nuclear decommissioning fund design. Internal and external funds; risk and return; fund accumulation, recommendations. Interim performance standard for Palo Verde nuclear plant.

49. **Penn.** PUC R-850152, Philadelphia Electric rate case; Utility Users Committee and University of Pennsylvania. January 14 1986.

    Limerick-1 rate effects. Capacity benefits, fuel savings, operating costs, capacity factors, and net benefits to ratepayers. Design of phase-in proposals.

50. **Mass.** DPU 85-270;, Western Massachusetts Electric rate case; Massachusetts Attorney General. March 19 1986.

    Prudence of Northeast Utilities in generation planning related to Millstone 3 construction: decisions to start and continue construction, failure to reduce ownership share, failure to pursue alternatives. Review of industry literature, cost and schedule histories, and retrospective cost-benefit analyses.

51. **Penn.** PUC R-850290, Philadelphia Electric auxiliary service rates; Albert Einstein Medical Center, University of Pennsylvania, and Amtrak. March 24 1986.

    Review of utility proposals for supplementary and backup rates for small power producers and cogenerators. Load diversity, cost of peaking capacity, value of generation, price signals, and incentives. Formulation of alternative supplementary rate.

52. **N.M.** PSC 2004, Public Service of New Mexico Palo Verde issues; New Mexico Attorney General. May 7 1986.

    Recommendations for power-plant performance standards for Palo Verde nuclear units 1, 2, and 3.

53. **Ill.** CC 86-0325, Iowa-Illinois Gas and Electric Co. rate investigation; Illinois Office of Public Counsel. August 13 1986.

    Determination of excess capacity based on reliability and economic concerns. Identification of specific units associated with excess capacity. Required reserve margins.

54. **N.M.** PSC 2009, El Paso Electric rate moderation program; New Mexico Attorney General. August 18 1986. (Not presented).

    Prudence of EPE in generation planning related to Palo Verde nuclear construction, including failure to reduce ownership share and failure to pursue alternatives. Review of industry literature, cost and schedule histories, and retrospective cost-benefit analyses.

    Recommendation for rate-base treatment; proposal of power plant performance standards.

55. **City of Boston Public Improvements Commission,** transfer of Boston Edison district heating steam system to Boston Thermal Corporation; Boston Housing Authority. December 18 1986.

    History and economics of steam system; possible motives of Boston Edison in seeking sale; problems facing Boston Thermal; information and assurances required prior to Commission approval of transfer.

56. **Mass. Division of Insurance,** hearing to fix and establish 1987 automobile insurance rates; Massachusetts Attorney General and State Rating Bureau. December 1986 and January 1987.

    Profit margin calculations, including methodology, implementation, derivation of cash flows, installment income, income tax status, and return to shareholders.

57. **Mass. DPU** 87-19, petition for adjudication of development facilitation program; Hull (Mass.) Municipal Light Plant. January 21 1987.

    Estimation of potential load growth; cost of generation, transmission, and distribution additions. Determination of hook-up charges. Development of residential load estimation procedure reflecting appliance ownership, dwelling size.

58. **N.M. PSC** 2004, Public Service of New Mexico nuclear decommissioning fund; New Mexico Attorney General. February 19 1987.

    Decommissioning cost and likely operating life of nuclear plants. Review of utility funding proposal. Development of alternative proposal. Ratemaking treatment.

59. **Mass. DPU** 86-280, Western Massachusetts Electric rate case; Massachusetts Energy Office. March 9 1987.

    Marginal cost rate design issues. Superiority of long-run marginal cost over short-run marginal cost as basis for rate design. Relationship of Consumer reaction, utility planning process, and regulatory structure to rate design approach. Implementation of short-run and long-run rate designs. Demand versus energy charges, economic development rates, spot pricing.

60. **Mass. Division of Insurance** 87-9, 1987 Workers' Compensation rate filing; State Rating Bureau. May 1987.

    Profit-margin calculations, including methodology, implementation, surplus requirements, investment income, and effects of 1986 Tax Reform Act.

61. **Texas PUC** 6184, economic viability of South Texas Nuclear Plant #2; Committee for Consumer Rate Relief. August 17 1987.

    Nuclear plant operating parameter projections; capacity factor, O&M, capital additions, decommissioning, useful life. STNP-2 cost and schedule projections. Potential for conservation.

62. **Minn. PUC** ER-015/GR-87-223, Minnesota Power rate case; Minnesota Department of Public Service. August 17 1987.

    Excess capacity on MP system; historical, current, and projected. Review of MP planning prudence prior to and during excess; efforts to sell capacity. Cost of excess capacity. Recommendations for ratemaking treatment.

63. **Mass. Division of Insurance** 87-27, 1988 automobile insurance rates; Massachusetts Attorney General and State Rating Bureau. September 2 1987. Rebuttal October 8 1987.

    Underwriting profit margins. Effect of 1986 Tax Reform Act. Biases in calculation of average margins.

64. **Mass. DPU** 88-19, power Sales Contract from Riverside Steam and Electric to Western Massachusetts Electric; Riverside Steam and Electric. November 4 1987.

    Comparison of risk from QF contract and utility avoided-cost sources. Risk of oil dependence. Discounting cash flows to reflect risk.

65. **Mass. Division of Insurance** 87-53, 1987 Workers' Compensation rate refiling; State Rating Bureau. December 14 1987.

    Profit-margin calculations including updating of data, compliance with Commissioner's order, treatment of surplus and risk, interest rate calculation, and investment tax rate calculation.

66. **Mass. Division of Insurance,** 1987 and 1988 automobile insurance remand rates; Massachusetts Attorney General and State Rating Bureau. February 5 1988.

    Underwriting profit margins. Provisions for income taxes on finance charges. Relationships between allowed and achieved margins, between statewide and nationwide data, and between profit allowances and cost projections.

67. **Mass. DPU** 86-36, investigation into the pricing and ratemaking treatment to be afforded new electric generating facilities which are not qualifying facilities; Conservation Law Foundation. May 2 1988.

    Cost recovery for utility conservation programs. Compensating for lost revenues. Utility incentive structures.

68. **Mass. DPU** 88-123, petition of Riverside Steam & Electric Company; Riverside Steam and Electric Company. May 18 1988 and November 8 1988.

    Estimation of avoided costs of Western Massachusetts Electric Company. Nuclear capacity factor projections and effects on avoided costs. Avoided cost of energy interchange and power plant life extensions. Differences between median and expected oil prices. Salvage value of cogeneration facility. Off-system energy purchase projections. Reconciliation of avoided cost projection.

69. **Mass.** **DPU** 88-67, Boston Gas Company; Boston Housing Authority. June 17 1988.

Estimation of annual avoidable costs, 1988 to 2005, and levelized avoided costs. Determination of cost recovery and carrying costs for conservation investments. Standards for assessing conservation cost-effectiveness. Evaluation of cost-effectiveness of utility funding of proposed natural gas conservation measures.

70. **R.I.** **PUC** 1900, Providence Water Supply Board tariff filing; Conservation Law Foundation, Audubon Society of Rhode Island, and League of Women Voters of Rhode Island. June 24 1988.

Estimation of avoidable water supply costs. Determination of costs of water conservation. Conservation cost-benefit analysis.

71. **Mass. Division of Insurance** 88-22, 1989 automobile insurance rates; Massachusetts Attorney General and State Rating Bureau; Profit Issues, August 12 1988, supplemented August 19 1988; Losses and Expenses, September 16 1988.

Underwriting profit margins. Effects of 1986 Tax Reform Act. Taxation of common stocks. Lag in tax payments. Modeling risk and return over time. Treatment of finance charges. Comparison of projected and achieved investment returns.

72. **Vt.** **PSB** 5270 Module 6, investigation into least-cost investments, energy efficiency, conservation, and the management of demand for energy; Conservation Law Foundation, Vermont Natural Resources Council, and Vermont Public Interest Research Group. September 26 1988.

Cost recovery for utility conservation programs. Compensation of utilities for revenue losses and timing differences. Incentive for utility participation.

73. **Vt. House of Representatives, Natural Resources Committee,** House Act 130; "Economic Analysis of Vermont Yankee Retirement"; Vermont Public Interest Research Group. February 21 1989.

Projection of capacity factors, operating and maintenance expense, capital additions, overhead, replacement power costs, and net costs of Vermont Yankee.

74. **Mass.** **DPU** 88-67 Phase II, Boston Gas company conservation program and rate design; Boston Gas Company. March 6 1989.

Estimation of avoided gas cost; treatment of non-price factors; estimation of externalities; identification of cost-effective conservation.

75. **Vt.** **PSB** 5270, status conference on conservation and load management policy settlement; Central Vermont Public Service, Conservation Law Foundation, Vermont Natural Resources Council, Vermont Public Interest Research Group, and Vermont Department of Public Service. May 1 1989.

Cost-benefit test for utility conservation programs. Role of externalities. Cost recovery concepts and mechanisms. Resource allocations, cost allocations, and equity considerations. Guidelines for conservation preapproval mechanisms. Incentive mechanisms and recovery of lost revenues.

76. **Boston Housing Authority Court** 05099, Gallivan Boulevard Task Force vs. Boston Housing Authority, et al.; Boston Housing Authority. June 16 1989.

Effect of master-metering on consumption of natural gas and electricity. Legislative and regulatory mandates regarding conservation.

77. **Mass. DPU** 89-100, Boston Edison rate case; Massachusetts Energy Office. June 30 1989.

Prudence of BECo's decision to spend $400 million from 1986–88 on returning the Pilgrim nuclear power plant to service. Projections of nuclear capacity factors, O&M, capital additions, and overhead. Review of decommissioning cost, tax effect of abandonment, replacement power cost, and plant useful life estimates. Requirements for prudence and used-and-useful analyses.

78. **Mass. DPU** 88-123, petition of Riverside Steam and Electric Company; Riverside Steam and Electric. July 24 1989. Rebuttal, October 3 1989.

Reasonableness of Northeast Utilities' 1987 avoided cost estimates. Projections of nuclear capacity factors, economy purchases, and power plant operating life. Treatment of avoidable energy and capacity costs and of off-system sales. Expected versus reference fuel prices.

79. **Mass. DPU** 89-72, Statewide Towing Association police-ordered towing rates; Massachusetts Automobile Rating Bureau. September 13 1989.

Review of study supporting proposed increase in towing rates. Critique of study sample and methodology. Comparison to competitive rates. Supply of towing services. Effects of joint products and joint sales on profitability of police-ordered towing. Joint testimony with I. Goodman.

80. **Vt. PSB** 5330, application of Vermont utilities for approval of a firm power and energy contract with Hydro-Quebec; Conservation Law Foundation, Vermont Natural Resources Council, Vermont Public Interest Research Group. December 19 1989. Surrebuttal February 6 1990.

Analysis of a proposed 450-MW, 20-year purchase of Hydro-Quebec power by twenty-four Vermont utilities. Comparison to efficiency investment in Vermont, including potential for efficiency savings. Analysis of Vermont electric energy supply. Identification of possible improvements to proposed contract.

Critique of conservation potential analysis. Planning risk of large supply additions. Valuation of environmental externalities.

81. **Mass. DPU** 89-239, inclusion of externalities in energy-supply planning, acquisition, and dispatch for Massachusetts utilities. December 1989; April 1990; May 1990.

Critique of Division of Energy Resources report on externalities. Methodology for evaluating external costs. Proposed values for environmental and economic externalities of fuel supply and use.

82. **California PUC,** incorporation of environmental externalities in utility planning and pricing; Coalition of Energy Efficient and Renewable Technologies. February 21 1990.

Approaches for valuing externalities for inclusion in setting power purchase rates. Effect of uncertainty on assessing externality values.

83. **Ill. CC** 90-0038, proceeding to adopt a least-cost electric-energy plan for Commonwealth Edison Company; City of Chicago. May 25 1990. Joint rebuttal testimony with David Birr, August 14 1990.

Problems in Commonwealth Edison's approach to demand-side management. Potential for cost-effective conservation. Valuing externalities in least-cost planning.

84. **Md. PSC** 8278, adequacy of Baltimore Gas & Electric's integrated resource plan; Maryland Office of People's Counsel. September 18 1990.

Rationale for demand-side management. BG&E's problems in approach to DSM planning. Potential for cost-effective conservation. Valuation of environmental externalities. Recommendations for short-term DSM program priorities.

85. **Ind. URC,** integrated-resource-planning docket; Indiana Office of Utility Consumer Counselor. November 1 1990.

Integrated resource planning process and methodology, including externalities and screening tools. Incentives, screening, and evaluation of demand-side management. Potential of resource bidding in Indiana.

86. **Mass. DPU** 89-141, 90-73, 90-141, 90-194, 90-270; preliminary review of utility treatment of environmental externalities in October qualifying-facilities filings; Boston Gas Company. November 5 1990.

Generic and specific problems in Massachusetts utilities' RFPs with regard to externality valuation requirements. Recommendations for corrections.

87. **Mass. EFSC** 90-12/90-12A, adequacy of Boston Edison proposal to build combined-cycle plant; Conservation Law Foundation. December 14 1990.

Problems in Boston Edison's treatment of demand-side management, supply option analysis, and resource planning. Recommendations of mitigation options.

88. **Maine PUC** 90-286, adequacy of conservation program of Bangor Hydro Electric; Penobscot River Coalition. February 19 1991.

Role of utility-sponsored DSM in least-cost planning. Bangor Hydro's potential for cost-effective conservation. Problems with Bangor Hydro's assumptions about customer investment in energy efficiency measures.

89. Va. **SCC** PUE900070, Order establishing commission investigation; Southern Environmental Law Center. March 6 1991.

Role of utilities in promoting energy efficiency. Least-cost planning objectives of and resource acquisition guidelines for DSM. Ratemaking considerations for DSM investments.

90. Mass. **DPU** 90-261-A, economics and role of fuel-switching in the DSM program of the Massachusetts Electric Company; Boston Gas Company. April 17 1991.

Role of fuel-switching in utility DSM programs and specifically in Massachusetts Electric's. Establishing comparable avoided costs and comparison of electric and gas system costs. Updated externality values.

91. Private arbitration, Massachusetts Refusetech Contractual Request for Adjustment to Service Fee; Massachusetts Refusetech. May 13 1991.

NEPCo rates for power purchases from the New England Solid Waste Compact plant. Fuel price and avoided cost projections vs. realities.

92. Vt. **PSB** 5491, cost-effectiveness of Central Vermont's commitment to Hydro Quebec purchases; Conservation Law Foundation. July 19 1991.

Changes in load forecasts and resale markets since approval of HQ purchases. Effect of HQ purchase on DSM.

93. S.C. **PSC** 91-216-E, cost recovery of Duke Power's DSM expenditures; South Carolina Department of Consumer Affairs. Direct, September 13 1991; Surrebuttal October 2 1991.

Problems with conservation plans of Duke Power, including load building, cream skimming, and inappropriate rate designs.

94. Md. **PSC** 8241 Phase II, review of Baltimore Gas & Electric's avoided costs; Maryland Office of People's Counsel. September 19 1991.

Development of direct avoided costs for DSM. Problems with BG&E's avoided costs and DSM screening. Incorporation of environmental externalities.

95. Bucksport (Maine) Planning Board, AES/Harriman Cove shoreland zoning application; Conservation Law Foundation and Natural Resources Council of Maine. October 1 1991.

New England's power surplus. Costs of bringing AES/Harriman Cove on line to back out existing generation. Alternatives to AES.

96. **Mass. DPU** 91-131, update of externalities values adopted in Docket 89-239; Boston Gas Company. October 4 1991. Rebuttal, December 13 1991.

Updates on pollutant externality values. Addition of values for chlorofluorocarbons, air toxics, thermal pollution, and oil import premium. Review of state regulatory actions regarding externalities.

97. **Fla. PSC** 910759, petition of Florida Power Corporation for determination of need for proposed electrical power plant and related facilities; Floridians for Responsible Utility Growth. October 21 1991.

Florida Power's obligation to pursue integrated resource planning and failure to establish need for proposed facility. Methods to increase scope and scale of demand-side investment.

98. **Fla. PSC** 910833-EI, petition of Tampa Electric Company for a determination of need for proposed electrical power plant and related facilities; Floridians for Responsible Utility Growth. October 31 1991.

Tampa Electric's obligation to pursue integrated resource planning and failure to establish need for proposed facility. Methods to increase scope and scale of demand-side investment.

99. **Penn. PUC** I-900005, R-901880; investigation into demand-side management by electric utilities; Pennsylvania Energy Office. January 10 1992.

Appropriate cost recovery mechanism for Pennsylvania utilities. Purpose and scope of direct cost recovery, lost revenue recovery, and incentives.

100. **S.C. PSC** 91-606-E, petition of South Carolina Electric and Gas for a certificate of public convenience and necessity for a coal-fired plant; South Carolina Department of Consumer Affairs. January 20 1992.

Justification of plant certification under integrated resource planning. Failures in SCE&G's DSM planning and company potential for demand-side savings.

101. **Mass. DPU** 92-92, adequacy of Boston Edison's street-lighting options; Town of Lexington. June 22 1992.

Efficiency and quality of street-lighting options. Boston Edison's treatment of high-quality street lighting. Corrected rate proposal for the Daylux lamp. Ownership of public street lighting.

102. **S.C. PSC** 92-208-E, integrated-resource plan of Duke Power Company; South Carolina Department of Consumer Affairs. August 4 1992.

Problems with Duke Power's DSM screening process, estimation of avoided cost, DSM program design, and integration of demand-side and supply-side planning.

103. **N.C. UC** E-100 Sub 64, integrated-resource-planning docket; Southern Environmental Law Center. September 29 1992.

General principles of integrated resource planning, DSM screening, and program design. Review of the IRPs of Duke Power Company, Carolina Power & Light Company, and North Carolina Power.

104. **Ont. EAB** Ontario Hydro Demand/Supply Plan Hearings, *Environmental Externalities Valuation and Ontario Hydro's Resource Planning* (3 vols.); Coalition of Environmental Groups. October 1992.

Valuation of environmental externalities from fossil fuel combustion and the nuclear fuel cycle. Application to Ontario Hydro's supply and demand planning.

105. **Texas PUC** 110000, application of Houston Lighting and Power company for a certificate of convenience and necessity for the DuPont Project; Destec Energy, Inc. September 28 1992.

Valuation of environmental externalities from fossil fuel combustion and the application to the evaluation of proposed cogeneration facility.

106. **Maine BEP,** in the matter of the Basin Mills Hydroelectric Project application; Conservation Intervenors. November 16 1992.

Economic and environmental effects of generation by proposed hydro-electric project.

107. **Md. PSC** 8473, review of the power sales agreement of Baltimore Gas and Electric with AES Northside; Maryland Office of People's Counsel. November 16 1992.

Non-price scoring and unquantified benefits; DSM potential as alternative; environmental costs; cost and benefit estimates.

108. **N.C. UC** E-100 Sub 64, analysis and investigation of least cost integrated resource planning in North Carolina; Southern Environmental Law Center. November 18 1992.

Demand-side management cost recovery and incentive mechanisms.

109. **S.C. PSC** 92-209-E, in re Carolina Power & Light Company; South Carolina Department of Consumer Affairs. November 24 1992.

Demand-side-management planning: objectives, process, cost-effectiveness test, comprehensiveness, lost opportunities. Deficiencies in CP&L's portfolio. Need for economic evaluation of load building.

110 **Fla. DER** hearings on the Power Plant Siting Act; Legal Environmental Assistance Foundation. December 1992.

Externality valuation and application in power-plant siting. DSM potential, cost-benefit test, and program designs.

111. **Md. PSC** 8487, Baltimore Gas and Electric Company electric rate case. Direct, January 13 1993; rebuttal, February 4 1993.

Class allocation of production plant and O&M; transmission, distribution, and general plant; administrative and general expenses. Marginal cost and rate design.

112. **Md.** **PSC** 8179, Approval of amendment no. 2 to Potomac Edison purchase agreement with AES Warrior Run; Maryland Office of People's Counsel. January 29 1993.

Economic analysis of proposed coal-fired cogeneration facility.

113. **Mich.** **PSC** U-10102, Detroit Edison rate case; Michigan United Conservation Clubs. February 17 1993.

Least-cost planning; energy efficiency planning, potential, screening, avoided costs, cost recovery, and shareholder incentives.

114. **Ohio** **PUC** 91-635-EL-FOR, 92-312-EL-FOR, 92-1172-EL-ECP; Cincinnati Gas and Electric demand-management programs; City of Cincinnati. April 1993.

Demand-side-management planning, program designs, potential savings, and avoided costs.

115. **Mich.** **PSC** U-10335, Consumers Power rate case; Michigan United Conservation Clubs. October 1993.

Least-cost planning; energy efficiency planning, potential, screening, avoided costs, cost recovery, and shareholder incentives.

116. **Ill.** **CC** 92-0268, electric-energy plan for Commonwealth Edison; City of Chicago. Direct, February 1 1994; rebuttal, September 1994.

Cost-effectiveness screening of demand-side management programs and measures; estimates by Commonwealth Edison of costs avoided by DSM and of future cost, capacity, and performance of supply resources.

117. **FERC** 2422 et al., application of James River–New Hampshire Electric, Public Service of New Hampshire, for licensing of hydro power; Conservation Law Foundation; 1993.

Cost-effective energy conservation available to the Public Service of New Hampshire; power-supply options; affidavit.

118. **Vt.** **PSB** 5270-CV-1,-3, and 5686; Central Vermont Public Service fuel-switching and DSM program design, on behalf of the Vermont Department of Public Service. Direct, April 1994; rebuttal, June 1994.

Avoided costs and screening of controlled water-heating measures; risk, rate impacts, participant costs, externalities, space- and water-heating load, benefit-cost tests.

119. **Fla.** **PSC** 930548-EG–930551-EG, conservation goals for Florida electric utilities; Legal Environmental Assistance Foundation, Inc. April 1994.

Integrated resource planning, avoided costs, rate impacts, analysis of conservation goals of Florida electric utilities.

120. **Vt. PSB** 5724, Central Vermont Public Service Corporation rate request; Vermont Department of Public Service. Joint surrebuttal testimony with John Plunkett. August 1994.

Costs avoided by DSM programs; Costs and benefits of deferring DSM programs.

121. **Mass. DPU** 94-49, Boston Edison integrated-resource-management plan; Massachusetts Attorney General. August 1994.

Least-cost planning, modeling, and treatment of risk.

122. **Mich. PSC** U-10554, Consumers Power Company DSM program and incentive; Michigan Conservation Clubs. November 1994.

Critique of proposed reductions in DSM programs; discussion of appropriate measurements of cost-effectiveness, role of DSM in competitive power markets.

123. **Mich. PSC** U-10702, Detroit Edison Company cost recovery, on behalf of the Residential Ratepayers Consortium. December 1994.

Impact of proposed changes to DSM plan on energy costs and power-supply-cost-recovery charges. Critique of proposed DSM changes; discussion of appropriate measurements of cost-effectiveness, role of DSM in competitive power markets.

124. **N.J. BRC** EM92030359, environmental costs of proposed cogeneration; Freehold Cogeneration Associates. November 1994.

Comparison of potential externalities from the Freehold cogeneration project with that from three coal technologies; support for the study "The Externalities of Four Power Plants."

125. **Mich. PSC** U-10671, Detroit Edison Company DSM programs; Michigan United Conservation Clubs. January 1995.

Critique of proposal to scale back DSM efforts in light of potential for competition. Loss of savings, increase of customer costs, and decrease of competitiveness. Discussion of appropriate measurements of cost-effectiveness, role of DSM in competitive power markets.

126. **Mich. PSC** U-10710, power-supply-cost-recovery plan of Consumers Power Company; Residential Ratepayers Consortium. January 1995.

Impact of proposed changes to DSM plan on energy costs and power-supply-cost-recovery charges. Critique of proposed DSM changes; discussion of appropriate measurements of cost-effectiveness, role of DSM in competitive power markets.

127. **FERC** 2458 and 2572, Bowater–Great Northern Paper hydropower licensing; Conservation Law Foundation. February 1995.

Comments on draft environmental impact statement relating to new licenses for two hydropower projects in Maine. Applicant has not adequately considered how energy conservation can replace energy lost due to habitat-protection or -enhancement measures.

128. **N.C. UC** E-100 Sub 74, Duke Power and Carolina Power & Light avoided costs; Hydro-Electric–Power Producer's Group. February 1995.

Critique and proposed revision of avoided costs offered to small hydro-power producers by Duke Power and Carolina Power and Light.

129. **New Orleans City Council** UD-92-2A and -2B, least-cost IRP for New Orleans Public Service and Louisiana Power & Light; Alliance for Affordable Energy. Direct, February 1995; rebuttal, April 1995.

Critique of proposal to scale back DSM efforts in light of potential competition.

130. **D.C. PSC** FC917 II, prudence of DSM expenditures of Potomac Electric Power Company; Potomac Electric Power Company. Rebuttal testimony, February 1995.

Prudence of utility DSM investment; prudence standards for DSM programs of the Potomac Electric Power Company.

131. **Ont. Energy Board** EBRO 490, DSM cost recovery and lost-revenue–adjustment mechanism for Consumers Gas Company; Green Energy Coalition. April 1995.

Demand-side-management cost recovery. Lost-revenue–adjustment mechanism for Consumers Gas Company.

132. **New Orleans City Council** CD-85-1, New Orleans Public Service rate increase; Alliance for Affordable Energy. Rebuttal, May 1995.

Allocation of costs and benefits to rate classes.

133. **Mass. DPU** Docket DPU-95-40, Mass. Electric cost-allocation; Massachusetts Attorney General. June 1995.

Allocation of costs to rate classes. Critique of cost-of-service study. Implications for industry restructuring.

134. **Md. PSC** 8697, Baltimore Gas & Electric gas rate increase; Maryland Office of People's Counsel. July 1995.

Rate design, cost-of-service study, and revenue allocation.

135. **N.C. UC** E-2 Sub 669. December 1995.

Need for new capacity. Energy-conservation potential and model programs.

136. **Arizona CC** U-1933-95-317, Tucson Electric Power rate increase; Residential Utility Consumer Office. January 1996.

Review of proposed rate settlement. Used-and-usefulness of plant. Rate design. DSM potential.

137. **Ohio PUC** 95-203-EL-FOR; Campaign for an Energy-Efficient Ohio. February 1996

Long-term forecast of Cincinnati Gas and Electric Company, especially its DSM portfolio. Opportunities for further cost-effective DSM savings. Tests of cost effectiveness. Role of DSM in light of industry restructuring; alternatives to traditional utility DSM.

138 **Vt. PSB** 5835, Central Vermont Public Service Company rates; Vermont Department of Public Service. February 1996.

Design of load-management rates of Central Vermont Public Service Company.

139. **Md. PSC** 8720, Washington Gas Light DSM; Maryland Office of People's Counsel. May 1996.

Avoided costs of Washington Gas Light Company; integrated least-cost planning.

140. **Mass. DPU** 96-100, Massachusetts Utilities' Stranded Costs; Massachusetts Attorney General. Oral testimony in support of "estimation of Market Value, Stranded Investment, and Restructuring Gains for Major Massachusetts Utilities," July 1996.

Stranded costs. Calculation of loss or gain. Valuation of utility assets.

141. **Mass. DPU** 96-70, Essex County Gas Company rates; Massachusetts Attorney General. July 1996.

Market-based allocation of gas-supply costs of Essex County Gas Company.

142. **Mass. DPU** 96-60, Fall River Gas Company rates; Massachusetts Attorney General. Direct, July 1996; surrebuttal, August 1996.

Market-based allocation of gas-supply costs of Fall River Gas Company.

143. **Md. PSC** 8725, Maryland electric-utilities merger; Maryland Office of People's Counsel. July 1996.

Proposed merger of Baltimore Gas & Electric Company, Potomac Electric Power Company, and Constellation Energy. Cost allocation of merger benefits and rate reductions.

144. **N.H. PUC** DR 96-150, Public Service Company of New Hampshire stranded costs; New Hampshire Office of Consumer Advocate. December 1996.

Market price of capacity and energy; value of generation plant; restructuring gain and stranded investment; legal status of PSNH acquisition premium; interim stranded-cost charges.

145. Ont. Energy Board EBRO 495, LRAM and shared-savings incentive for DSM performance of Consumers Gas; Green Energy Coalition. March 1997.

LRAM and shared-savings incentive mechanisms in rates for the Consumers Gas Company Ltd.

146. New York PSC 96-E-0897, Consolidated Edison restructuring plan; City of New York. April 1997.

Electric-utility competition and restructuring; critique of proposed settlement of Consolidated Edison Company; stranded costs; market power; rates; market access.

147. Vt. PSB 5980, proposed statewide energy plan; Vermont Department of Public Service. Direct, August 1997; rebuttal, December 1997.

Justification for and estimation of statewide avoided costs; guidelines for distributed IRP.

148. Mass. DPU 96-23, Boston Edison restructuring settlement; Utility Workers Union of America. September 1997.

Performance incentives proposed for the Boston Edison company.

149. Vt. PSB 5983, Green Mountain Power rate increase; Vermont Department of Public Service. Direct, October 1997; rebuttal, December 1997.

In three separate pieces of prefiled testimony, addressed the Green Mountain Power Corporation's (1) distributed-utility-planning efforts, (2) avoided costs, and (3) prudence of decisions relating to a power purchase from Hydro-Quebec.

150. Mass. DPU 97-63, Boston Edison proposed reorganization; Utility Workers Union of America. October 1997.

Increased costs and risks to ratepayers and shareholders from proposed reorganization; risks of diversification; diversion of capital from regulated to unregulated affiliates; reduction in Commission authority.

151. Mass. DTE 97-111, Commonwealth Energy proposed restructuring; Cape Cod Light Compact. Joint testimony with Jonathan Wallach, January 1998.

Critique of proposed restructuring plan filed to satisfy requirements of the electric-utility restructuring act of 1997. Failure of the plan to foster competition and promote the public interest.

152. N.H. PUC Docket DR 97-241, Connecticut Valley Electric fuel and purchased-power adjustments; City of Claremont, N.H. February 1998.

Prudence of continued power purchase from affiliate; market cost of power; prudence disallowances and cost-of-service ratemaking.

153. **Md.** **PSC** 8774, APS-DQE merger; Maryland Office of People's Counsel. February 1998.

Proposed power-supply arrangements between APS's potential operating subsidiaries; power-supply savings; market power.

154. **Vt.** **PSB** 6018, Central Vermont Public Service Co. rate increase; Vermont Department of Public Service. February 1998.

Prudence of decisions relating to a power purchase from Hydro-Quebec. Reasonableness of avoided-cost estimates. Quality of DU planning.

155. **Maine** **PUC** 97-580, Central Maine Power restructuring and rates; Maine Office of Public Advocate. May 1998; Surrebuttal, August 1998.

Determination of stranded costs; gains from sales of fossil, hydro, and biomass plant; treatment of deferred taxes; incentives for stranded-cost mitigation; rate design.

156. **Mass.** **DTE** 98-89, purchase of Boston Edison municipal street lighting; Towns of Lexington and Acton. Affidavit, August 1998.

Valuation of municipal streetlighting; depreciation; applicability of unbundled rate.

157. **Vt.** **PSB** 6107, Green Mountain Power rate increase; Vermont Department of Public Service. Direct, September 1998; Surrebuttal drafted but not filed, November 2000.

Prudence of decisions relating to a power purchase from Hydro-Quebec. Least-cost planning and prudence. Quality of DU planning.

158. **Mass.** **DTE** 97-120, Western Massachusetts Electric Company proposed restructuring; Massachusetts Attorney General. Joint testimony with Jonathan Wallach, October 1998. Joint surrebuttal with Jonathan Wallach, January 1999.

Market value of the three Millstone nuclear units under varying assumptions of plant performance and market prices. Independent forecast of wholesale market prices. Value of Pilgrim and TMI-1 asset sales.

159. **Md.** **PSC** 8794 and 8804, BG&E restructuring and rates; Maryland Office of People's Counsel. Direct, December 1998; rebuttal, March 1999.

Implementation of restructuring. Valuation of generation assets from comparable-sales and cash-flow analyses. Determination of stranded cost or gain.

160. **Md.** **PSC** 8795; Delmarva Power & Light restructuring and rates; Maryland Office of People's Counsel. December 1998.

Implementation of restructuring. Valuation of generation assets and purchases from comparable-sales and cash-flow analyses. Determination of stranded cost or gain.

161. **Md. PSC** 8797, Potomac Edison Company restructuring and rates; Maryland Office of People's Counsel. Direct, January 1999; rebuttal, March 1999.

Implementation of restructuring. Valuation of generation assets and purchases from comparable-sales and cash-flow analyses. Determination of stranded cost or gain.

162. **Conn. DPUC** 99-02-05, Connecticut Light and Power Company stranded costs; Connecticut Office of Consumer Counsel. April 1999.

Projections of market price. Valuation of purchase agreements and nuclear and non-nuclear assets from comparable-sales and cash-flow analyses.

163. **Conn. DPUC** 99-03-04, United Illuminating Company stranded costs; Connecticut Office of Consumer Counsel. April 1999.

Projections of market price. Valuation of purchase agreements and nuclear assets from comparable-sales and cash-flow analyses.

164. **Wash. UTC** UE-981627, PacifiCorp–Scottish Power merger, Office of the Attorney General. June 1999.

Review of proposed performance standards and valuation of performance. Review of proposed low-income assistance.

165. **Utah PSC** 98-2035-04, PacifiCorp–Scottish Power merger, Utah Committee of Consumer Services. June 1999.

Review of proposed performance standards and valuation of performance.

166. **Conn. DPUC** 99-03-35, United Illuminating Company proposed standard offer; Connecticut Office of Consumer Counsel. July 1999.

Design of standard offer by rate class. Design of price adjustments to preserve rate decrease. Market valuations of nuclear plants. Short-term stranded cost

167. **Conn. DPUC** 99-03-36, Connecticut Light and Power Company proposed standard offer; Connecticut Office of Consumer Counsel. Direct, July 1999; supplemental, July 1999.

Design of standard offer by rate class. Design of price adjustments to preserve rate decrease. Market valuations of nuclear plants. Short-term stranded cost.

168. **W. Va. PSC** 98-0452-E-GI, electric-industry restructuring, West Virginia Consumer Advocate. July 1999.

Market value of generating assets of, and restructuring gain for, Potomac Edison, Monongahela Power, and Appalachian Power. Comparable-sales and cash-flow analyses.

169. **Ont. Energy Board** RP-1999-0034, Ontario performance-based rates; Green Energy Coalition. September 1999.

Rate design. Recovery of demand-side-management costs under PBR. Incremental costs.

170. **Conn. DPUC** 99-08-01, standards for utility restructuring; Connecticut Office of Consumer Counsel. Direct, November 1999; supplemental, January 2000.

Appropriate role of regulation. T&D reliability and service quality. Performance standards and customer guarantees. Assessing generation adequacy in a competitive market.

171. **Conn. Superior Court** CV 99-049-7239, Connecticut Light and Power Company stranded costs; Connecticut Office of Consumer Counsel. Affidavit, December 1999.

Errors of the Conn. DPUC in deriving discounted-cash-flow valuations for Millstone and Seabrook, and in setting minimum bid price.

172. **Conn. Superior Court** CV 99-049-7597, United Illuminating Company stranded costs; Connecticut Office of Consumer Counsel. December 1999.

Errors of the Conn. DPUC, in its discounted-cash-flow computations, in selecting performance assumptions for Seabrook, and in setting minimum bid price.

173. **Ont. Energy Board** RP-1999-0044, Ontario Hydro transmission-cost allocation and rate design; Green Energy Coalition. January 2000.

Cost allocation and rate design. Net vs. gross load billing. Export and wheeling-through transactions. Environmental implications of utility proposals.

174. **Utah PSC** 99-2035-03, PacifiCorp Sale of Centralia plant, mine, and related facilities; Utah Committee of Consumer Services. January 2000.

Prudence of sale and management of auction. Benefits to ratepayers. Allocation and rate treatment of gain.

175. **Conn. DPUC** 99-09-12, Nuclear Divestiture by Connecticut Light & Power and United Illuminating; Connecticut Office of Consumer Counsel. January 2000.

Market for nuclear assets. Optimal structure of auctions. Value of minority rights. Timing of divestiture.

176. **Ont. Energy Board** RP-1999-0017, Union Gas PBR proposal; Green Energy Coalition. March 2000.

Lost-revenue-adjustment and shared-savings incentive mechanisms for Union Gas DSM programs. Standards for review of targets and achievements, computation of lost revenues. Need for DSM expenditure true-up mechanism.

177. **N.Y. PSC** 99-S-1621, Consolidated Edison steam rates; City of New York. April 2000.

Allocation of costs of former cogeneration plants, and of net proceeds of asset sale. Economic justification for steam-supply plans. Depreciation rates. Weather normalization and other rate adjustments.

178. **Maine** **PUC** 99-666, Central Maine Power alternative rate plan; Maine Public Advocate. Direct, May 2000; Surrebuttal, August 2000.

Likely merger savings. Savings and rate reductions from recent mergers. Implications for rates.

179. **Mass.** **EFSB** 97-4, Massachusetts Municipal Wholesale Electric Company gas-pipeline proposal; Town of Wilbraham, Mass. June 2000.

Economic justification for natural-gas pipeline. Role and jurisdiction of EFSB.

180. **Conn.** **DPUC** 99-09-03; Connecticut Natural Gas Corporation merger and rate plan; Connecticut office of Consumer Counsel. September 2000.

Performance-based ratemaking in light of mergers. Allocation of savings from merger. Earnings-sharing mechanism.

181. **Conn.** **DPUC** 99-09-12RE01, Proposed Millstone sale; Connecticut Office of Consumer Counsel. November 2000.

Requirements for review of auction of generation assets. Allocation of proceeds between units.

182. **Mass.** **DTE** 01-25, Purchase of streetlights from Commonwealth Electric; Cape Light Compact. January 2001

Municipal purchase of streetlights; Calculation of purchase price under state law; Determination of accumulated depreciation by asset.

183. **Conn.** **DPUC** 00-12-01 and 99-09-12RE03, Connecticut Light & Power rate design and standard offer; Connecticut Office of Consumer Counsel. March 2001.

Rate design and standard offer under restructuring law; Future rate impacts; Transition to restructured regime; Comparison of Connecticut and California restructuring challenges.

184. **Vt.** **PSB** 6460 & 6120, Central Vermont Public Service rates; Vermont Department of Public Service. Direct, March 2001; Surrebuttal, April 2001.

Review of decision in early 1990s to commit to long-term uneconomic purchase from Hydro Québec. Calculation of present damages from imprudence.

185. **N.J.** **BPU** EM00020106, Atlantic City Electric Company sale of fossil plants; New Jersey Ratepayer Advocate. Affidavit, May 2001.

Comparison of power-supply contracts. Comparison of plant costs to replacement power cost. Allocation of sales proceeds between subsidiaries.

186. **N.J. BPU** GM00080564, Public Service Electric and Gas transfer of gas supply contracts; New Jersey Ratepayer Advocate. Direct, May 2001.

Transfer of gas transportation contracts to unregulated affiliate. Potential for market power in wholesale gas supply and electric generation. Importance of reliable gas supply. Valuation of contracts. Effect of proposed requirements contract on rates. Regulation and design of standard-offer service.

187. **Conn. DPUC** 99-04-18 Phase 3, 99-09-03 Phase 2; Southern Connecticut Natural Gas and Connecticut Natural Gas rates and charges; Connecticut Office of Consumer Counsel. Direct, June 2001; supplemental, July 2001.

Identifying, quantifying, and allocating merger-related gas-supply savings between ratepayers and shareholders. Establishing baselines. Allocations between affiliates. Unaccounted-for gas.

188. **N.J. BPU** EX01050303, New Jersey electric companies' procurement of basic supply; New Jersey Ratepayer Advocate. August 2001.

Review of proposed statewide auction for purchase of power requirements. Market power. Risks to ratepayers of proposed auction.

189. **N.Y. PSC** 00-E-1208, Consolidated Edison rates; City of New York. October 2001.

Geographic allocation of stranded costs. Locational and postage-stamp rates. Causation of stranded costs. Relationship between market prices for power and stranded costs.

190. **Mass. DTE** 01-56, Berkshire Gas Company; Massachusetts Attorney General. October 2001.

Allocation of gas costs by load shape and season. Competition and cost allocation.

191. **N.J. BPU** EM00020106, Atlantic City Electric proposed sale of fossil plants; New Jersey Ratepayer Advocate. December 2001.

Current market value of generating plants vs. proposed purchase price.

192. **Vt. PSB** 6545, Vermont Yankee proposed sale; Vermont Department of Public Service. January 2002.

Comparison of sales price to other nuclear sales. Evaluation of auction design and implementation. Review of auction manager's valuation of bids.

193. **Conn. Siting Council** 217, Connecticut Light & Power proposed transmission line from Plumtree to Norwalk; Connecticut Office of Consumer Counsel. March 2002.

Nature of transmission problems. Potential for conservation and distributed resources to defer, reduce or avoid transmission investment. CL&P transmission planning process. Joint testimony with John Plunkett.

194. **Vt.** **PSB** 6596, Citizens Utilities rates; Vermont Department of Public Service. Direct, March 2002; rebuttal, May 2002.

Review of 1991 decision to commit to long-term uneconomic purchase from Hydro Québec. Alternatives; role of transmission constraints. Calculation of present damages from imprudence.

195. **Conn.** **DPUC** 01-10-10, United Illuminating rate plan; Connecticut Office of Consumer Counsel. April 2002

Allocation of excess earnings between shareholders and ratepayers. Asymmetry in treatment of over- and under-earning. Accelerated amortization of stranded costs. Effects of power-supply developments on ratepayer risks. Effect of proposed rate plan on utility risks and required return.

196. **Conn.** **DPUC** 01-12-13RE01, Seabrook proposed sale; Connecticut Office of Consumer Counsel. July 2002

Comparison of sales price to other nuclear sales. Evaluation of auction design and implementation. Assessment of valuation of purchased-power contracts.

197. **Ont. Energy Board** RP-2002-0120, review of transmission-system code; Green Energy Coalition. October 2002.

Cost allocation. Transmission charges. Societal cost-effectiveness. Environmental externalities.

198. **N.J.** **BPU** ER02080507, Jersey Central Power & Light rates; N.J. Division of the Ratepayer Advocate. Phase I December 2002; Phase II (oral) July 2003.

Prudence of procurement of electrical supply. Documentation of procurement decisions. Comparison of costs for subsidiaries with fixed versus flow-through cost recovery.

199. **Conn.** **DPUC** 03-07-02, CL&P rates; AARP. October 2003

Proposed distribution investments, including prudence of prior management of distribution system and utility's failure to make investments previously funded in rates. Cost controls. Application of rate cap. Legislative intent.

200. **Conn.** **DPUC** 03-07-01, CL&P transitional standard offer; AARP. November 2003.

Application of rate cap. Legislative intent.

201. **Vt.** **PSB** 6596, Vermont Electric Power Company and Green Mountain Power Northwest Reliability transmission plan; Conservation Law Foundation. December 2003.

Inadequacies of proposed transmission plan. Failure of to perform least-cost planning. Distributed resources.

202. **Ohio PUC** 03-2144-EL-ATA, Ohio Edison, Cleveland Electric, and Toledo Edison Cos. rates and transition charges; Green Mountain Energy Co. February 2004.

Pricing of standard-offer service in competitive markets. Critique of anticompetitive features of proposed standard-offer supply, including non-bypassable charges.

203. **N.Y. PSC** 03-G-1671 & 03-S-1672, Consolidated Edison company steam and gas rates; City of New York. Direct March 2004; rebuttal April 2004; settlement June 2004.

Prudence and cost allocation for the East River Repowering Project. Gas and steam energy conservation. Opportunities for cogeneration at existing steam plants.

204. **N.Y. PSC** 04-E-0572, Consolidated Edison rates and performance; City of New York. Direct, September 2004; rebuttal, October 2004.

Consolidated Edison's role in promoting adequate supply and demand resources. Integrated resource and T&D planning. Performance-based ratemaking and streetlighting.

205. **Ont. Energy Board** RP 2004-0188, cost recovery and DSM for Ontario electric-distribution utilities; Green Energy Coalition. Exhibit, December 2004.

Differences in ratemaking requirements for customer-side conservation and demand management versus utility-side efficiency improvements. Recovery of lost revenues or incentives. Reconciliation mechanism.

206. **Mass. DTE** 04-65, Cambridge Electric Light Co. streetlighting; City of Cambridge. Direct, October 2004; supplemental, January 2005.

Calculation of purchase price of street lights by the City of Cambridge.

207. **N.Y. PSC** 04-W-1221, rates, rules, charges, and regulations of United Water New Rochelle; Town of Eastchester and City of New Rochelle. Direct, February 2005.

Size and financing of proposed interconnection. Rate design. Water-mains replacement and related cost recovery. Lost and unaccounted-for water.

208. **N.Y. PSC** 05-M-0090, system-benefits charge; City of New York. Comments, March 2005.

Assessment and scope of, and potential for, New York system-benefits charges.

209. **Md. PSC** 9036, Baltimore Gas & Electric rates; Maryland Office of People's Counsel. Direct, August 2005.

Allocation of costs. Design of rates. Interruptible and firm rates.

210. **B.C. UC** 3698388, British Columbia Hydro resource-acquisition plan; British Columbia Sustainable Energy Association and Sierra Club of Canada BC Chapter. September 2005.

Renewable energy and DSM. Economic tests of cost-effectiveness. Costs avoided by DSM.

211. **Conn. DPUC** 05-07-18, financial effect of long-term power contracts; Connecticut Office of Consumer Counsel. September 2005.

Assessment of effect of DSM, distributed generation, and capacity purchases on financial condition of utilities.

212. **Conn. DPUC** 03-07-01RE03 & 03-07-15RE02, incentives for power procurement; Connecticut Office of Consumer Counsel. Direct, September 2005; Additional, April 2006.

Utility obligations for generation procurement. Application of standards for utility incentives. Identification and quantification of effects of timing, load characteristics, and product definition.

213. **Conn. DPUC** Docket 05-10-03, Connecticut L&P; time-of-use, interruptible, and seasonal rates; Connecticut Office of Consumer Counsel. Direct and Supplemental Testimony February 2006.

Seasonal and time-of-use differentiation of generation, congestion, transmission and distribution costs; fixed and variable peak-period timing; identification of pricing seasons and seasonal peak periods; cost-effectiveness of time-of-use rates.

214. **Ont. Energy Board** Case EB-2005-0520, Union Gas rates; School Energy Coalition. Evidence, April 2006.

Rate design related to splitting commercial rate class into two classes. New break point, cost allocation, customer charges, commodity rate blocks.

215. **Ont. Energy Board** EB-2006-0021, Natural-gas demand-side-management generic issues proceeding; School Energy Coalition. Evidence, June 2006.

Multi-year planning and budgeting; lost-revenue adjustment mechanism; determining savings for incentives; oversight; program screening.

216. **Ind. URC** 42943 and 43046, Vectren Energy DSM proceedings; Citizens Action Coalition. Direct, June 2006.

Rate decoupling and energy-efficiency goals.

217. **Penn. PUC** 00061346, Duquesne Lighting; Real-time pricing; PennFuture. Direct, July 2006; surrebuttal August 2006.

Real-time and time-dependent pricing; benefits of time-dependent pricing; appropriate metering technology; real-time rate design and customer information

218. **Penn. PUC** R-00061366 et al., rate-transition-plan proceedings of Metropolitan Edison and Pennsylvania Electric; Real-time pricing; PennFuture. Direct, July 2006; surrebuttal August 2006.

Real-time and time-dependent pricing; appropriate metering technology; real-time rate design and customer information.

219. **Conn.** **DPUC** 06-01-08, Connecticut L&P procurement of power for standard service and last-resort service; Connecticut Office of Consumer Counsel. Reports and technical hearings quarterly since September 2006 to October 2013.

Conduct of auction; review of bids; comparison to market prices; selection of winning bidders.

220. **Conn.** **DPUC** 06-01-08, United Illuminating procurement of power for standard service and last-resort service; Connecticut Office of Consumer Counsel. Reports and technical hearings quarterly August 2006 to October 2013.

Conduct of auction; review of bids; comparison to market prices; selection of winning bidders.

221. **N.Y.** **PSC** Case No. 06-M-1017, policies, practices, and procedures for utility commodity supply service; City of New York. Comments, November and December 2006.

Multi-year contracts, long-term planning, new resources, procurement by utilities and other entities, cost recovery.

222. **Conn.** **DPUC** 06-01-08, procurement of power for standard service and last-resort service, lessons learned; Connecticut Office Of Consumer Counsel. Comments and Technical Conferences December 2006 and January 2007.

Sharing of data and sources; benchmark prices; need for predictability, transparency and adequate review; utility-owned resources; long-term firm contracts.

223. **Ohio** **PUC** PUCO 05-1444-GA-UNC, recovery of conservation costs, decoupling, and rate-adjustment mechanisms for Vectren Energy Delivery of Ohio; Ohio Consumers' Counsel. February 2007.

Assessing cost-effectiveness of natural-gas energy-efficiency programs. Calculation of avoided costs. Impact on rates. System benefits of DSM.

224. **N.Y.** **PSC** 06-G-1332, Consolidated Edison Rates and Regulations; City of New York. March 2007.

Gas energy efficiency: benefits to customers, scope of cost-effective programs, revenue decoupling, shareholder incentives.

225. **Alb.** **EUB** 1500878, ATCo Electric rates; Association of Municipal Districts & Counties and Alberta Federation of Rural Electrical Associations. May 2007.

Direct assignment of distribution costs to street lighting. Cost causation and cost allocation. Minimum-system and zero-intercept classification.

226. **Conn. DPUC** 07-04-24, review of capacity contracts under Energy Independence Act; Connecticut Office of Consumer Counsel. Direct (with Jonathan Wallach), June 2007.

Assessment of proposed capacity contracts for new combined-cycle, peakers and DSM. Evaluation of contracts for differences, modeling of energy, capacity and forward-reserve markets. Corrections of errors in computation of costs, valuation of energy-price effects of peakers, market-driven expansion plans and retirements, market response to contracted resource additions, DSM proposal evaluation.

227. **N.Y. PSC** 07-E-0524, Consolidated Edison electric rates; City of New York. September 2007.

Energy-efficiency planning. Recovery of DSM costs. Decoupling of rates from sales. Company incentives for DSM. Advanced metering. Resource planning.

228. **Man. PUB** 136-07, Manitoba Hydro rates; Resource Conservation Manitoba and Time to Respect Earth's Ecosystem. February 2008.

Revenue allocation, rate design, and demand-side management. Estimation of marginal costs and export revenues.

229. **Mass. EFSB** 07-7, DPU 07-58 & -59; proposed Brockton Power Company plant; Alliance Against Power Plant Location. March 2008

Regional supply and demand conditions. Effects of plant construction and operation on regional power supply and emissions.

230. **Conn. DPUC** 08-01-01, peaking generation projects; Connecticut Office of Consumer Counsel. Direct (with Jonathan Wallach), April 2008.

Assessment of proposed peaking projects. Valuation of peaking capacity. Modeling of energy margin, forward reserves, other project benefits.

231. **Ont. Energy Board** 2007-0905, Ontario Power Generation payments; Green Energy Coalition. April 2008.

Cost of capital for Hydro and nuclear investments. Financial risks of nuclear power.

232. **Utah** PSC 07-035-93, Rocky Mountain Power Rates; Utah Committee of Consumer Services. July 2008

Cost allocation and rate design. Cost of service. Correct classification of generation, transmission, and purchases.

233. **Ont. Energy Board** 2007-0707, Ontario Power Authority integrated system plan; Green Energy Coalition, Penimba Institute, and Ontario Sustainable Energy Association. Evidence (with Jonathan Wallach and Richard Mazzini), August 2008.

Critique of integrated system plan. Resource cost and characteristics; finance cost. Development of least-cost green-energy portfolio.

234. **N.Y. PSC** 08-E-0596, Consolidated Edison electric rates; City of New York. September 2008.

Estimated bills, automated meter reading, and advanced metering. Aggregation of building data. Targeted DSM program design. Using distributed generation to defer T&D investments.

235. **Conn. DPUC** 08-07-01, Integrated resource plan; Connecticut Office of Consumer Counsel. September 2008.

Integrated resource planning scope and purpose. Review of modeling and assumptions. Review of energy efficiency, peakers, demand response, nuclear, and renewables. Structuring of procurement contracts.

236. **Man. PUB** 2008 MH EIIR, Manitoba Hydro intensive industrial rates; Resource Conservation Manitoba and Time to Respect Earth's Ecosystem. November 2008.

Marginal costs. Rate design. Time-of-use rates.

237. **Md. PSC** 9036, Columbia Gas rates; Maryland Office of People's Counsel. January 2009.

Cost allocation and rate design. Critique of cost-of-service studies.

238. **Vt. PSB** 7440, extension of authority to operate Vermont Yankee; Conservation Law Foundation and Vermont Public Interest Research Group. Direct, February 2009; Surrebuttal, May 2009.

Adequacy of decommissioning funding. Potential benefits to Vermont of revenue-sharing provision. Risks to Vermont of underfunding decommissioning fund.

239. **N.S. UARB** 01439, Nova Scotia Power DSM and cost recovery; Nova Scotia Consumer Advocate. May 2009.

Recovery of demand-side-management costs and lost revenue.

240. **N.S. UARB** 0496, proposed biomass project; Nova Scotia Consumer Advocate. June 2009.

Procedural, planning, and risk issues with proposed power-purchase contract. Biomass price index. Nova Scotia Power's management of other renewable contracts.

241. **Conn. Siting Council** 370A, Connecticut Light & Power transmission projects; Connecticut Office of Consumer Counsel. July 2009.

Need for transmission projects. Modeling of transmission system. Realistic modeling of operator responses to contingencies

242. **Mass. DPU** 09-39, NGrid rates; Mass. Department of Energy Resources. August 2009.

Revenue-decoupling mechanism. Automatic rate adjustments.

243. **Utah PSC** 09-035-23, Rocky Mountain Power rates; Utah Office of Consumer Services. Direct, October 2009; rebuttal, November 2009.

Cost-of-service study. Cost allocators for generation, transmission, and substation.

244. **Utah PSC** 09-035-15, Rocky Mountain Power energy-cost-adjustment mechanism; Utah Office of Consumer Services. Direct, November 2009; surrebuttal, January 2010.

Automatic cost-adjustment mechanisms. Net power costs and related risks. Effects of energy-cost-adjustment mechanisms on utility performance.

245. **Penn. PUC** R-2009-2139884, Philadelphia Gas Works energy efficiency and cost recovery; Philadelphia Gas Works. December 2009.

Avoided gas costs. Recovery of efficiency-program costs and lost revenues. Rate impacts of DSM.

246. **B.C. UC** 3698573, British Columbia Hydro rates; British Columbia Sustainable Energy Association and Sierra Club British Columbia. February 2010.

Rate design and energy efficiency.

247. **Ark. PSC** 09-084-U, Entergy Arkansas rates; National Audubon Society and Audubon Arkansas. Direct, February 2010; surrebuttal, April 2010.

Recovery of revenues lost to efficiency programs. Determination of lost revenues. Incentive and recovery mechanisms.

248. **Ark. PSC** 10-010-U, Energy efficiency; National Audubon Society and Audubon Arkansas. Direct, March 2010; reply, April 2010.

Regulatory framework for utility energy-efficiency programs. Fuel-switching programs. Program administration, oversight, and coordination. Rationale for commercial and industrial efficiency programs. Benefit of energy efficiency.

249. **Ark. PSC** 08-137-U, Generic rate-making; National Audubon Society and Audubon Arkansas. Direct, March 2010; supplemental, October 2010; reply, October 2010.

Calculation of avoided costs. Recovery of utility energy-efficiency-program costs and lost revenues. Shareholder incentives for efficiency-program performance.

250. **Plymouth, Mass., Superior Court** Civil Action No. PLCV2006-00651-B (Hingham Municipal Lighting Plant v. Gas Recovery Systems LLC et al.), Breach of agreement; defendants. Affidavit, May 2010.

Contract interpretation. Meaning of capacity measures. Standard practices in capacity agreements. Power-pool rules and practices. Power planning and procurement.

251. **N.S. UARB** 02961, Port Hawkesbury biomass project; Nova Scotia Consumer Advocate. June 2010.

Least-cost planning and renewable-energy requirements. Feasibility versus alternatives. Unknown or poorly estimated costs.

252. **Mass. DPU** 10-54, NGrid purchase of long-term power from Cape Wind; Natural Resources Defense Council et al. July 2010.

Effects of renewable-energy projects on gas and electric market prices. Impacts on system reliability and peak loads. Importance of PPAs to renewable development. Effectiveness of proposed contracts as price edges.

253. **Md. PSC** 9230, Baltimore Gas & Electric rates; Maryland Office of People's Counsel. Direct, July 2010; rebuttal, surrebuttal, August 2010.

Allocation of gas- and electric-distribution costs. Critique of minimum-system analyses and direct assignment of shared plant. Allocation of environmental compliance costs. Allocation of revenue increases among rate classes.

254. **Ont. Energy Board** 2010-0008, Ontario Power Generation facilities charges; Green Energy Coalition. Evidence, August 2010.

Critique of including a return on CWIP in current rates. Setting cost of capital by business segment.

255. **N.S. UARB** Matter No. 03454, Heritage Gas rates; Nova Scotia Consumer Advocate. October 2010.

Cost allocation. Cost of capital. Effect on rates of growth in sales.

256. **Man. PUB** 17/10, Manitoba Hydro rates; Resource Conservation Manitoba and Time to Respect Earth's Ecosystem. December 2010.

Revenue-allocation and rate design. DSM program.

257. **N.S. UARB** 03665, Nova Scotia Power depreciation rates; Nova Scotia Consumer Advocate. February 2011.

Depreciation and rates.

258. **New Orleans City Council** UD-08-02, Entergy IRP rules; Alliance for Affordable Energy. December 2010.

Integrated resource planning: Purpose, screening, cost recovery, and generation planning.

259. **N.S. UARB** NSPI-P-892, depreciation Rates of Nova Scotia Power; Nova Scotia Consumer Advocate. February 2011.

Steam-plant retirement dates, post-retirement use, timing of decommissioning and removal costs.

260. **N.S. UARB** 03632, renewable-energy community-based feed-in tariffs; Nova Scotia Consumer Advocate. March 2011.

Adjustments to estimate of cost-based feed-in tariffs. Rate effects of feed-in tariffs.

261. **Mass. EFSB** 10-2/DPU 10-131, 10-132; NStar transmission; Town of Sandwich, Mass. Direct, May 2011; Surrebuttal, June 2011.

Need for new transmission; errors in load forecasting; probability of power outages.

262. **Utah PSC** 10-035-124, Rocky Mountain Power rate case; Utah Office of Consumer Services. June 2011.

Load data, allocation of generation plants, scrubbers, power purchases, and service drops. Marginal cost study: inclusion of all load-related transmission projects, critique of minimum- and zero-intercept methods for distribution. Residential rate design.

263. **N.S. UARB** 04104; Nova Scotia Power general rate application; Nova Scotia Consumer Advocate. August 2011.

Cost allocation: allocation of costs of wind power and substations. Rate design: marginal-cost-based rates, demand charges, time-of-use rates.

264. **N.S. UARB** 04175, Load-retention tariff; Nova Scotia Consumer Advocate. August 2011.

Marginal cost of serving very large industrial electric loads; risk, incentives and rate design.

265. **Ark. PSC** 10-101-R, Rulemaking re self-directed energy efficiency for large customers; National Audubon Society and Audubon Arkansas. July 2011.

Structuring energy-efficiency programs for large customers.

266. **Okla. CC** PUD 201100077, current and pending federal regulations and legislation affecting Oklahoma utilities; Sierra Club. Comments July, October 2011; presentation July 2011.

Challenges facing Oklahoma coal plants; efficiency, renewable and conventional resources available to replace existing coal plants; integrated environmental compliance planning.

267. **Nevada PUC** 11-08019, integrated analysis of resource acquisition, Sierra Club. Comments, September 2011; hearing, October 2011.

Scoping of integrated review of cost-effectiveness of continued operation of Reid Gardner 1–3 coal units.

268. **La. PSC** R-30021, Louisiana integrated-resource-planning rules; Alliance for Affordable Energy. Comments, October 2011.

Scoping of integrated review of cost-effectiveness of continued operation of Reid Gardner 1–3 coal units.

269. **Okla.** CC PUD 201100087, Oklahoma Gas and Electric Company electric rates; Sierra Club. November 2011.

Resource monitoring and acquisition. Benefits to ratepayers of energy conservation and renewables. Supply planning

270. **Ky.** PSC 2011-00375, Kentucky utilities' purchase and construction of power plants; Sierra Club and National Resources Defense Council. December 2011.

Assessment of resources, especially renewables. Treatment of risk. Treatment of future environmental costs.

271. **N.S.** UARB M04819, demand-side-management plan of Efficiency Nova Scotia; Nova Scotia Consumer Advocate. May 2012.

Avoided costs. Allocation of costs. Reporting of bill effects.

272. **Kansas** CC 12-GIMX-337-GIV, utility energy-efficiency programs; The Climate and Energy Project. June 2012.

Cost-benefit tests for energy-efficiency programs. Collaborative program design.

273. **N.S.** UARB M04862, Port Hawksbury load-retention mechanism; Nova Scotia Consumer Advocate. June 2012.

Effect on ratepayers of proposed load-retention tariff. Incremental capital costs, renewable-energy costs, and costs of operating biomass cogeneration plant.

274. **Utah** PSC 11-035-200, Rocky Mountain Power Rates; Utah Office of Consumer Council. June 2012.

Cost allocation. Estimation of marginal customer costs.

275. **Ark.** PSC 12-008-U, environmental controls at Southwestern Electric Power Company's Flint Creek plant; Sierra Club. Direct, June 2012; rebuttal, August 2012; further, March 2013.

Costs and benefits of environmental retrofit to permit continued operation of coal plant, versus other options including purchased gas generation, efficiency, and wind. Fuel-price projections. Need for transmission upgrades.

276. **U.S.** EPA EPA-R09-OAR-2012-0021, air-quality implementation plan; Sierra Club. September 2012.

Costs, financing, and rate effects of Apache coal-plant scrubbers. Relative incomes in service territories of Arizona Coop and other utilities.

277. **Arkansas** PSC Docket No. 07-016-U; Entergy Arkansas' integrated resource plan; Audubon Arkansas. Comments, September 2012.

Estimation of future gas prices. Estimation of energy-efficiency potential. Screening of resource decisions. Wind costs.

278. **Vt. PSB** 7862, Entergy Nuclear Vermont and Entergy Nuclear Operations petition to operate Vermont Yankee; Conservation Law Foundation. October 2012.

Effect of continued operation on market prices. Value of revenue-sharing agreement. Risks of underfunding decommissioning fund.

279. **Man. PUB** 2012–13 GRA, Manitoba Hydro rates; Green Action Centre. November 2012.

Estimation of marginal costs. Fuel switching.

280. **N.S. UARB** M05339, Capital Plan of Nova Scotia Power; Nova Scotia Consumer Advocate. January 2013.

Economic and financial modeling of investment. Treatment of AFUDC.

281. **N.S. UARB** M05416, South Canoe wind project of Nova Scotia Power; Nova Scotia Consumer Advocate. January 2013.

Revenue requirements. Allocation of tax benefits. Ratemaking.

282. **N.S. UARB** 05419; Maritime Link transmission project and related contracts, Nova Scotia Consumer Advocate and Small Business Advocate. Direct, April 2013; supplemental (with Seth Parker), November 2013.

Load forecast, including treatment of economy energy sales. Wind power cost forecasts. Cost effectiveness and risk of proposed project. Opportunities for improving economics of project.

283. **Ont. Energy Board** 2012-0451/0433/0074, Enbridge Gas Greater Toronto Area project; Green Energy Coalition. June 2013, revised August 2013.

Estimating gas pipeline and distribution costs avoidable through gas DSM and curtailment of electric generation. Integrating DSM and pipeline planning.

284. **N.S. UARB** 05092, tidal-energy feed-in-tariff rate; Nova Scotia Consumer Advocate. August 2013.

Purchase rate for test and demonstration projects. Maximizing benefits under rate-impact caps. Pricing to maximize provincial advantage as a hub for emerging tidal-power industry.

285. **N.S. UARB** 05473, Nova Scotia Power 2013 cost-of-service study; Nova Scotia Consumer Advocate. October 2013.

Cost-allocation and rate design.

286. B.C. UC 3698715 & 3698719; performance-based ratemaking plan for FortisBC companies; British Columbia Sustainable Energy Association and Sierra Club British Columbia. Direct (with John Plunkett), December 2013.

Rationale for enhanced gas and electric DSM portfolios. Correction of utility estimates of electric avoided costs. Errors in program screening. Program potential. Recommended program ramp-up rates.

287. Conn. PURA Docket No. 14-01-01, Connecticut Light and Power Procurement of Standard Service and Last-Resort Service. July and October 2014.

Proxy for review of bids. Oversight of procurement and selection process.

288. Conn. PURA Docket No. 14-01-02, United Illuminating Procurement of Standard Service and Last-Resort Service. January, April, July, and October 2014.

Proxy for review of bids. Oversight of procurement and selection process.

289. Man. PUB 2014, need for and alternatives to proposed hydro-electric facilities; Green Action Centre. Evidence (with Wesley Stevens) February 2014.

Potential for fuel switching, DSM, and wind to meet future demand.

290. Utah PSC 13-035-184, Rocky Mountain Power Rates; Utah Office of Consumer Services. May 2014.

Class cost allocation. Classification and allocation of generation plant and purchased power. Principles of cost-causation. Design of backup rates.

291. Minn. PSC E002/GR-13-868, Northern States Power rates; Clean Energy Intervenors. Direct, June 2014; rebuttal, July 2014; surrebuttal, August 2014.

Inclining-block residential rate design. Rationale for minimizing customer charges.

292. Cal. PUC Rulemaking 12-06-013, electric rates and rate structures; Natural Resources Defense Council. September 2014.

Redesigning residential rates to simplify tier structure while maintaining efficiency and conservation incentives. Effect of marginal price on energy consumption. Realistic modeling of Consumer price response. Benefits of minimizing customer charges.

293. Md. PSC 9361, proposed merger of PEPCo Holdings into Exelon; Sierra Club and Chesapeake Climate Action Network. Direct, December 2014; surrebuttal, January 2015.

Effect of proposed merger on Consumer bills, renewable energy, energy efficiency, and climate goals.

294. N.S. UARB M06514, 2015 capital-expenditure plan of Nova Scotia Power; Nova Scotia Consumer Advocate. January 2015.

Economic evaluation of proposed projects. Treatment of AFUDC, overheads, and replacement costs of lost generation. Computation of rate effects of spending plan.

295. **N.S. UARB** M06733, supply agreement between Efficiency One and Nova Scotia Power; Nova Scotia Consumer Advocate. January 2015.

Avoided costs. Cost-effectiveness screening of DSM. Portfolio design. Affordability and bill effects.

296. **Md. PSC** 9153 et al., Maryland energy-efficiency programs; Maryland Office of People's Counsel. January 2015.

Costs avoided by demand-side management. Demand-reduction-induced price effects.

297. **Québec** Régie de L'énergie R-3876-2013 phase 1, Gaz Métro cost allocation and rate structure; Regroupement des organismes environnementaux en énergie and Union des consommateurs. February 2015

Classification of the area-spanning system; minimum system and more realistic approaches. Allocation of overhead, energy-efficiency, gas-supply, engineering-and-planning, and billing costs.

298. **Conn. PURA** Docket No. 15-01-01, Connecticut Light and Power Procurement of Standard Service and Last-Resort Service. February and July 2015.

Proxy for review of bids. Oversight of procurement and selection process.

299. **Conn. PURA** Docket No. 15-01-02, United Illuminating Procurement of Standard Service and Last-Resort Service. February, July, and October 2015.

Proxy for review of bids. Oversight of procurement and selection process.

300. **Ky. PSC** 2014-00371, Kentucky Utilities Company electric rates; Sierra Club. March 2015.

Review basis for higher customer charges, including cost allocation. Design of time-of-day rates.

301. **Ky. PSC** 2014-00372, Louisville Gas and Electric Company electric rates; Sierra Club. March 2015.

Review basis for higher customer charges, including cost allocation. Design of time-of-day rates.

302. **Mich. PSC** U-17767, DTE Electric Company rates; Michigan Environmental Council, Sierra Club, and Natural Resource Defense Council. May 2015.

Cost effectiveness of pollution-control retrofits versus retirements. Market prices. Costs of alternatives.

303. **Penn. PUC** P-2014-2459362, Philadelphia Gas Works DSM, universal-service, and energy-conservation plans; Philadelphia Gas Works. Direct, May 2015; Rebuttal, July 2015.

Avoided costs. Recovery of lost margin.

304. **PUC Ohio** Case No. 14-1693-EL-RDR, AEP Ohio Affiliate purchased-power agreement, Sierra Club. September 2015.

Economics of proposed PPA, market energy and capacity projections. Risk shifting. Lack of price stability and reliability benefits. Market viability of PPA units.

305. **N.S. UARB** Matter No. M06214, NS Power Renewable-to-Retail rate, Nova Scotia Consumer Advocate. November 2015.

Review of proposed design of rate for third-party sales of renewable energy to retail customers. Distribution, transmission and generation charges.

306. **PUC Texas** Docket No. 44941, El Paso Electric rates; Energy Freedom Coalition of America. December 2015.

Cost allocation and rate design. Effect of proposed DG rate on solar customers. Load shapes of residential customers with and without solar. Problems with demand charges.

ACRONYMS AND INITIALISMS

APS	Alleghany Power System
ASLB	Atomic Safety and Licensing Board
BEP	Board of Environmental Protection
BPU	Board of Public Utilities
BRC	Board of Regulatory Commissioners
CC	Corporation Commission
CMP	Central Maine Power
DER	Department of Environmental Regulation
DPS	Department of Public Service
DQE	Duquesne Light
DPUC	Department of Public Utilities Control
DSM	Demand-Side Management
DTE	Department of Telecommunications and Energy
EAB	Environmental Assessment Board
EFSB	Energy Facilities Siting Board
EFSC	Energy Facilities Siting Council
EUB	Energy and Utilities Board
FERC	Federal Energy Regulatory Commission
ISO	Independent System Operator
LRAM	Lost-Revenue-Adjustment Mechanism
NARUC	National Association of Regulatory Utility Commissioners
NEPOOL	New England Power Pool
NRC	Nuclear Regulatory Commission
OCA	Office of Consumer Advocate
PSB	Public Service Board
PBR	Performance-based Regulation
PSC	Public Service Commission
PUC	Public Utility Commission
PUB	Public Utilities Board
PURA	Public Utility Regulatory Authority
PURPA	Public Utility Regulatory Policy Act
SCC	State Corporation Commission
UARB	Utility and Review Board
USAEE	U.S. Association of Energy Economists
UC	Utilities Commission
URC	Utility Regulatory Commission
UTC	Utilities and Transportation Commission

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Data Requests Cited in Testimony

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POTOMAC ELECTRIC POWER COMPANY
MARYLAND CASE NO. 9418
RESPONSE TO OPC DATA REQUEST NO. 4

QUESTION NO. 28

PLEASE REFER TO THE DIRECT TESTIMONY OF KAREN LEFKOWITZ, PAGE 48, LINE 20 TO PAGE 49, LINE 7.

A. PLEASE PROVIDE SUPPORTING DOCUMENTATION AND CALCULATIONS IN ELECTRONIC FORMAT WITH ALL FORMULAE INTACT USED BY THE COMPANY TO QUANTIFY THE BENEFITS AND COSTS ATTRIBUTABLE TO ITS DYNAMIC PRICING PROGRAM.
B. PLEASE INDICATE THE DATES OF ALL PESC EVENTS SINCE THE SUMMER OF 2012.
C. PLEASE INDICATE THE ANNUAL NUMBER OF ANTICIPATED PESC EVENTS USED IN THE COMPANY'S DETERMINATION OF PESC EVENTS.
D. PLEASE PROVIDE THE ANNUAL AMOUNT OF BILL CREDITS PAID BY THE COMPANY FOR PESC EVENTS.
E. PLEASE PROVIDE THE PROJECTED ANNUAL AMOUNT OF BILL CREDITS TO BE PAID BY THE COMPANY FOR FUTURE PESC EVENTS.
F. PLEASE INDICATE IF THE COMPANY INCLUDED BILL CREDIT AMOUNTS IN DETERMINING THE COST-EFFECTIVENESS OF ITS DP PROGRAM. IF NOT, PLEASE EXPLAIN WHY NOT.
G. PLEASE INDICATE NUMBER OF PARTICIPANTS FOR EACH PESC EVENT.
H. PLEASE DEFINE PARTICIPANTS AND NON-PARTICIPANTS.
I. PLEASE INDICATE IF THE COMPANY ADJUSTS FOR FREE-RIDERSHIP IN ITS PESC EVENTS. IF SO, PLEASE EXPLAIN AND QUANTIFY. IF NOT, PLEASE EXPLAIN WHY NOT.

RESPONSE:

A. Please refer to Staff DR 6-1, Attachment C, Dynamic Pricing Benefits Tabs.
B. Please refer to Pepco's AMI Metrics Report for this information.
C. For AMI cost-effectiveness calculations, the Company has assumed that 16 hours of PESC events will be called annually.
D. The PESC annual bill credits are provided below.

Year	2012	2013	2014	2015	Total
PESC Bill Credit	$113,969	$2,478,210	$4,132,803	$8,277,474	$15,002,456

E. The forecast annual bill credits for 2016 are $9 million. The Company has not forecasted the annual bill credits beyond 2016.
F. Please refer to the response provided to OPC DR 2-12.

G. Please refer to Pepco's AMI Metrics Report for this information.

H. Participants are defined as customers who earned PESC bill credits for each event. Non-participants are defined as those customers who did not earn any bill credit for a specific event.

I. Free ridership estimates are considered through regression panel modeling. Please refer to Staff DR 6-1, Attachment C, Dynamic Pricing Tab.

SPONSOR: Karen R. Lefkowitz

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POTOMAC ELECTRIC POWER COMPANY
MARYLAND CASE NO. 9418
RESPONSE TO OPC DATA REQUEST NO. 3

QUESTION NO. 8

PLEASE REFER TO THE DIRECT TESTIMONY OF KAREN LEFKOWITZ, PAGE 19, LINES 17-18.

A. PLEASE PROVIDE SUPPORTING WORKBOOKS WITH FORMULAE INTACT AND SUPPORTING DOCUMENTATION RELIED UPON BY THE COMPANY TO ESTIMATE THE ANNUAL ANALYTICAL SUPPORT COSTS.
B. PLEASE EXPLAIN WHY ANALYTICAL SUPPORT COSTS FOR VALIDATION OF PROGRAM EFFECTIVENESS ENDS AFTER 2017.
C. PLEASE PROVIDE ALL REPORTS COMMISSIONED BY THE COMPANY TO DETERMINE THE PROGRAM'S EFFECTIVENESS.

RESPONSE:

A. Please refer to Staff DR 6-1 Attachment I – Tab "O&M Costs".
B. Beginning in 2018, the Company anticipates that it will be able to support the analytical requirements within the utility.
C. Please refer to Schedule (AF)-2 and (AF)-3 that are attached to Company Witness Faruqui's Direct Testimony. Please refer to OPC DR 3-8 Attachment A and Attachment B for the regression analysis performed by Brattle on the dynamic pricing events.

SPONSOR: Karen R. Lefkowitz/Ahmad Faruqui

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THE Brattle GROUP

MEMORANDUM

TO: [redacted]

FROM: [redacted]

SUBJ: Highlights of the Pepco Maryland 2013 Peak Energy Savings Credit (PESC) Program Analysis

DATE: May 28, 2015

I. Background

Pepco Maryland has deployed the Peak Energy Savings Credit (PESC) Program in the summer of 2013 and called two critical event days. Four additional PESC event days were called during the summer of 2014. Roughly 417,000 Pepco residential customers were eligible to participate in these events. Approximately 25 percent of the eligible customers also participated in Pepco's Energy Wise Rewards (EWR) Program that involved the cycling of the central air-conditioning compressors on PESC event days.

Pepco MD has retained The Brattle Group to undertake the impact evaluation of the PESC program during the summers of 2013 and 2014. In this study we analyze and report the engaged customer program performance. In the remainder of this memo, we describe our data, our methodology and the results of our analysis.

II. Data

Our analysis uses hourly AMI data on 416,767 customers and spans June 1st, 2013 through September 30th, 2013. Pepco MD called two events in the summer of 2013. Each of the remaining three events lasted four hours, with the first event days spanning from 1 pm through 5 pm and the second event day spanning from 2 pm through 6 pm. Table 1 presents the dates and average WTHIs for these event days during the event window and Figure 1 presents the average event window WTHI for each day during June through September 2013.

Table 1- 2013 PESC Program Event Days and Average WTHI

Event Day	Average WTHI During Event Window
08/21/2013	79.65
09/11/2013	83.19

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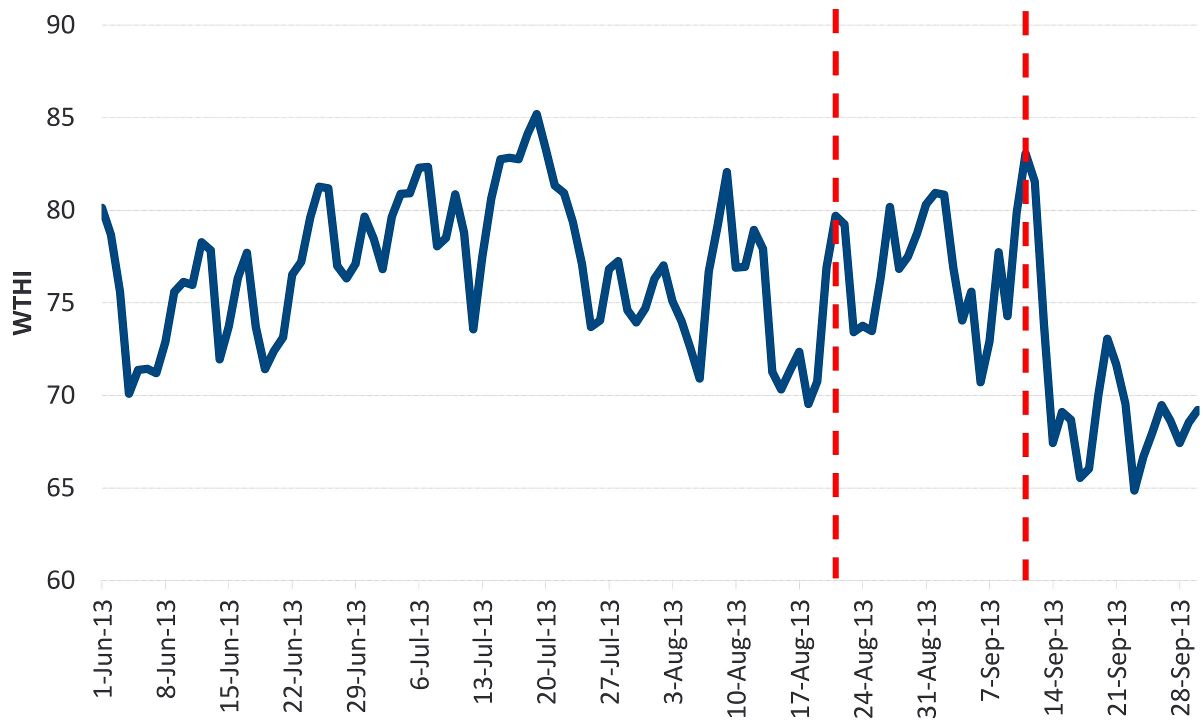
Figure 1- 2013 PESC Program Average WTHI from 1 pm through 6pm (June-September 2014)



Note: The first and second event windows were 1 pm through 5 pm and 2 pm through 6 pm, respectively. The above chart shows average WTHI for 1 pm through 6 pm to make event days directly comparable.

Out of 416,767 customers, 106,600 were also the participants of the EWR program (these customers will be referred to as PESC+EWR in the rest of this document). We have separately analyzed the performance of both PESC only and PESC+EWR groups; *however this memo will only report the results for the PESC only customers*.

III. Methodology

As indicated earlier, we have estimated the regression models using the "engaged participants" of the program in order to determine the peak reduction capability of the PESC program. We have defined engaged customers as those who received a positive rebate on a given event day, using

Pepco's Customer Baseline (CBL) Approach[1]. There are several alternative ways to define the engaged customers, however we have decided to determine the engaged customers using the CBL approach to be consistent with the manner that Pepco rewards customers for their participation. Table 2 reports the total eligible PESC only customers and the engaged PESC only customers for each of the 2013 event days.

Table 2- 2013 PESC Program PESC Only Customers: Eligible vs. Engaged

Event Day	CBL Approach	Total Eligible Customers
08/21/2013	245,048	308,167
09/11/2013	165,741	308,167

Note: Of the 308,167 eligible PESC only customers, roughly 136,000 received a rebate on both event days.

After identifying the engaged customers, we conducted a panel regression model that compares the event day usage of the customers to their non-event day usage after accounting for the weather differences between the two types of days. We estimated these regressions by event day and hour over each of the event hours (HE 14-18) separately. Our specification for Event Day 1, Hour 14 is presented below. Other event days and event hours also use the same specification, as this specification captures customers' weather dependent usage profiles fairly well. Appendix A presents the estimation results.

$$ln(kW_{it,h14}) = \beta_0 + \beta_1 * WTHI_{t,h14} + \beta_2 * WTHI\text{^}2_{t,h14} + \beta_3 * EventDay1xWTHI_{t,h14} + \varepsilon_{it,h14}$$

Where:

$ln(kW_{it,h14})$: Natural log of consumption for household i, at day t and hour 14.

$WTHI_{t,h14}$: Weighted temperature humidity index

$WTHI\text{^}2_{t,h14}$: WTHI squared

[1] Pepco MD's CBL approach looks at the 30 days (excluding weekends and holidays) prior to the event day and the day before the event day and picks the three highest usage days. Each customer's usage from noon to 8 pm on these three days is averaged and compared to the event day load.

$EventDay1xWTHI_{t,h14}$: Interaction of EventDay1 dummy variable with WTHI

$\varepsilon_{it,h14}$: Error term, clustered by household

IV. Results

After estimating the event day and event hour specific regressions, we calculated the hourly impacts by evaluating the estimated coefficients at each event day's particular WTHI conditions. Table 3 presents the average engaged customer impacts by event day and event hour.

Table 3- 2013 PESC Program Impact Estimates by Event Day, PESC Only Engaged Customers

Hour	**Event Day 1 (8/21/13) 1-5pm** Event Day Impact	**Event Day 2 (9/11/13) 2-6pm** Event Day Impact
14	-16.3%	*(na)*
15	-15.7%	-31.5%
16	-13.5%	-31.4%
17	-13.0%	-27.3%
18	*(na)*	-22.1%
Average Impact	**-14.6%**	**-28.1%**
Average WTHI	**79.65**	**83.19**

Based on the results presented on Table 3, we found that the engaged PESC only customers reduced their peak period usage by 14.6% on Event Day 1 and by 28.1% on Event Day 2. Event Day 2 had the greatest WTHI and the greatest impact of the two event days. Moreover, Event Day 1 was the first event day called in the summer, and therefore awareness could have been lower than that for Event Day 2, yielding lower impacts on Event Day 1. Therefore, these results are consistent with our expectations.

V. System Impacts

The next step in our analysis was to take the estimated impacts and calculate what the energy and system peak reduction capability of the PESC program has been based on the engaged customer performance in the summer of 2013.

A. Energy Reduction Capability

In order to calculate the energy reduction capability of the program, we first created a "but-for" load profile that represents what the average load of an average customer would be on an event day, if the event day had not been called. In order to calculate the but-for load, we have identified 19 non-event days with average peak WTHIs greater than or equal to 79 degrees[2]. Once we identified these days, we took the average load to create a but-for load profile for an event day in 2013. We further averaged the usage in the peak window (HE 14-18) of this load profile to create an average hourly peak period usage on a comparable non-event day.

In order to calculate the energy reduction capability of the PESC only program, we multiply the estimated percentage impacts with the but-for load times four and the number of engaged customers. We then gross-up this number for the residential loss factor for energy (1.0572), and obtain the energy reduction capability of the PESC program. Table 4 summarizes these results.

Table 4- 2013 PESC Program Energy Reduction Capability (MWh), PESC Only

Event Day	Avg. Peak WTHI	Engaged Customers	% Change in Peak	But-for Load (kW)	Energy Reduction Capability (MWh)
8/21/2013	79.6	245,048	-14.6%	2.5	-385.1
9/11/2013	83.2	165,741	-28.1%	2.5	-501.2
Average					**-443.2**

B. System Peak Reduction Capability

We have used PJM's system peak definition for Pepco MD service territory (HE 17 at 83.7 degrees) and selected July 19, 2013, a PJM designated system peak day for the Pepco Zone, to create our but-for load profile for the peak reduction capability calculations. We took the average of customer load profiles on July 19th, and reported HE 17 load as our but-for load.

Next, we multiply the but-for load with the peak reduction impact evaluated at 83.7 degrees and the number of engaged customers. We then gross-up this number for the residential loss factor

[2] We have selected 79 degrees as the threshold level, because the mildest event day in 2013, Event Day 1, had an average peak WTHI of 79.6 degrees.

for peak (1.0963), and obtain the system peak reduction capability of the PESC program. Table 5 summarizes these results.

Table 5- 2013 PESC Program System Peak Reduction Capability (MW), PESC Only (HE 17 at WTHI=83.7)

Event Day	HE 17 WTHI	Engaged Customers	% Change in HE 17 Usage	HE 17 But-for Load (kW)	Peak Reduction Capability (MW)
8/21/2013	83.7	245,048	-13.0%	3.2	-112.4
9/11/2013	83.7	165,741	-27.3%	3.2	-159.6
Average					**-136.0**

VI.Conclusion

In this study, we have determined the energy and system peak reduction capability of the PESC program based on the performance of the customers who have engaged in the program in the summer of 2013. Comparing these results to the similar results from the 2014 PESC program, we conclude that the PESC program results have been fairly consistent across the two summers. The performance of the programs may increase further if the number of engaged customers increase in the future.

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APPENDIX A- ESTIMATION RESULTS

Table A.1: 2013 PESC Only, Engaged Customers, Event Day 1

VARIABLES	(1) Hour 14	(2) Hour 15	(3) Hour 16	(4) Hour 17
Event Day 1 x WTHI	-0.00205***	-0.00197***	-0.00168***	-0.00163***
	(1.55e-05)	(1.51e-05)	(1.49e-05)	(1.49e-05)
WTHI	0.0438***	0.0410***	0.0690***	0.00880***
	(0.000179)	(0.000192)	(0.000141)	(0.000139)
WTHI^2	0.000184***	0.000241***	6.78e-05***	0.000467***
	(1.13e-06)	(1.29e-06)	(7.87e-07)	(1.10e-06)
Constant	-4.404***	-4.489***	-5.560***	-3.220***
	(0.00822)	(0.00842)	(0.00763)	(0.00612)
Observations	20,302,334	20,303,599	20,305,521	20,287,719
R-squared	0.215	0.227	0.230	0.222
Number of servicepointid	245,048	245,048	245,048	245,048

Robust standard errors in parentheses
*** p<0.01, ** p<0.05, * p<0.1

Table A.2: 2013 PESC Only, Engaged Customers, Event Day 2

VARIABLES	(1) Hour 15	(2) Hour 16	(3) Hour 17	(4) Hour 18
Event Day 2 x WTHI	-0.00378***	-0.00377***	-0.00330***	-0.00270***
	(1.92e-05)	(1.88e-05)	(1.86e-05)	(1.87e-05)
WTHI	0.0391***	0.0640***	0.00627***	0.0282***
	(0.000237)	(0.000173)	(0.000173)	(0.000283)
WTHI^2	0.000206***	5.20e-05***	0.000436***	0.000278***
	(1.59e-06)	(9.80e-07)	(1.37e-06)	(1.97e-06)
Constant	-4.199***	-5.147***	-2.911***	-3.570***
	(0.0103)	(0.00920)	(0.00746)	(0.0116)
Observations	13,730,926	13,732,145	13,720,200	13,720,174
R-squared	0.190	0.191	0.185	0.178
Number of servicepointid	165,741	165,741	165,741	165,741

Robust standard errors in parentheses
*** p<0.01, ** p<0.05, * p<0.1

THE Brattle GROUP

MEMORANDUM

TO: [redacted]

FROM: [redacted]

SUBJ: Highlights of the Pepco Maryland 2014 Peak Energy Savings Credit (PESC) Program Analysis

DATE: March 18, 2015

I. Background

Pepco Maryland has deployed the Peak Energy Savings Credit (PESC) Program in the summer of 2013 and called two critical event days. Four additional PESC event days were called during the summer of 2014. Roughly 470,000 Pepco residential customers were eligible to participate in these events. Approximately 30 percent of the eligible customers also participated in Pepco's Energy Wise Rewards (EWR) Program that involved the cycling of the central air-conditioning compressors on PESC event days.

Pepco MD has retained The Brattle Group to undertake the impact evaluation of the PESC program during the summers of 2013 and 2014. In this study we analyze and report the engaged customer program performance. In the remainder of this memo, we describe our data, our methodology and the results of our analysis.

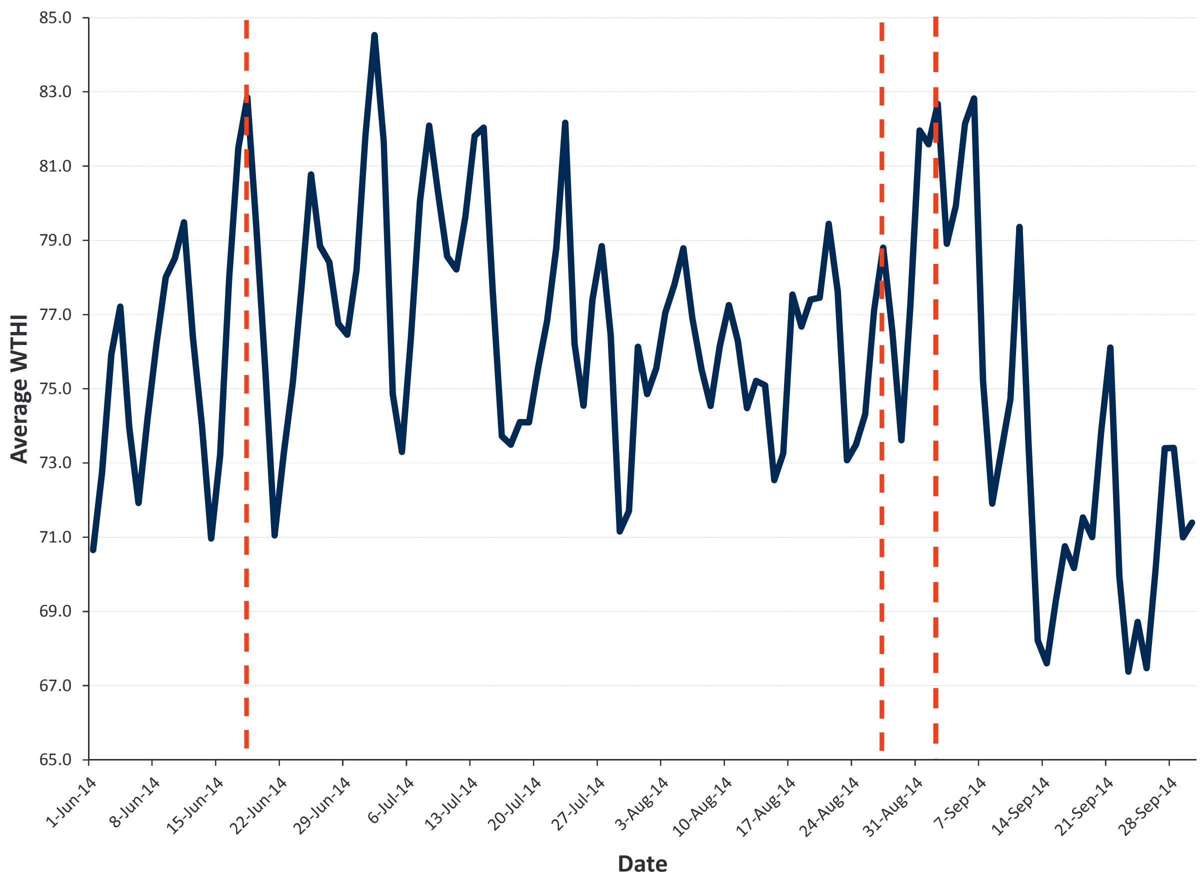
II. Data

Our analysis uses hourly AMI data on 469,240 customers and spans June 1st, 2014 through September 30th, 2014. Pepco MD called four events in the summer of 2014, but the last event (09/18/2014) was a one hour event and was excluded from our dataset. Each of the remaining three events lasted four hours, and from 2 pm through 6 pm. Table 1 presents the dates and average WTHIs for these event days during the event window and Figure 1 presents the average event window WTHI for each day during June through September 2014.

Table 1- 2014 PESC Program Event Days and Average WTHI

Event Day	Average WTHI (2 pm-6 pm)
06/18/2014	82.9
08/27/2014	78.8
09/02/2014	82.7

Figure 1- 2014 PESC Program Average WTHI during Event Window (June-September 2014)



Out of 469,240 customers, 139,059 were also the participants of the EWR program (these customers will be referred to as PESC+EWR in the rest of this document). We have separately analyzed the performance of both PESC only and PESC+EWR groups; *however this memo will only report the results for the PESC only customers.*

III. Methodology

As indicated earlier, we have estimated the regression models using the "engaged participants" of the program in order to determine the peak reduction capability of the PESC program. We have defined engaged customers as those who received a positive rebate on a given event day, using Pepco's Customer Baseline (CBL) Approach[1]. There are several alternative ways to define the engaged customers, however we have decided to determine the engaged customers using the CBL approach to be consistent with the manner that Pepco rewards customers for their participation. Table 2 reports the total eligible PESC only customers and the engaged PESC only customers for each of the 2014 event days.

Table 2- 2014 PESC Program PESC Only Customers: Eligible vs. Engaged

Event Day	CBL Approach	Total Eligible Customers
06/18/2014	149,966	330,181
08/27/2014	249,858	330,181
09/02/2014	190,401	330,181

Note: Of the 330,181 eligible PESC only customers, 208,955 received a rebate on at least two out of three event days.

After identifying the engaged customers, we conducted a panel regression model that compares the event day usage of the customers to their non-event day usage after accounting for the weather differences between the two types of days. We estimated these regressions by event day and hour over each of the event hours (HE 15-18) separately. Our specification for Event Day 1, Hour 15 is presented below. Other event days and event hours also use the same specification, as this specification captures customers' weather dependent usage profiles fairly well. Appendix A presents the estimation results.

$$ln(kW_{it,h15}) = \beta_0 + \beta_1 * WTHI_{t,h15} + \beta_2 * WTHI\char`^2_{t,h15} + \beta_3 * EventDay1xWTHI_{t,h15} + \varepsilon_{it,h15}$$

Where:

[1] Pepco MD's CBL approach looks at the 30 days (excluding weekends and holidays) prior to the event day and the day before the event day and picks the three highest usage days. Each customer's usage from noon to 8 pm on these three days is averaged and compared to the event day load.

$ln(kW_{it,h15})$: Natural log of consumption for household i, at day t and hour 15.

$WTHI_{t,h15}$: Weighted temperature humidity index

$WTHI\text{^}2_{t,h15}$: WTHI squared

$EventDay1xWTHI_{t,h15}$: Interaction of EventDay1 dummy variable with WTHI

$\varepsilon_{it,h15}$: Error term, clustered by household

IV. Results

After estimating the event day and event hour specific regressions, we calculated the hourly impacts by evaluating the estimated coefficients at each event day's particular WTHI conditions. Table 3 presents the average engaged customer impacts by event day and event hour.

Table 3- 2014 PESC Program Impact Estimates by Event Day, PESC Only Engaged Customers

	Event Day 1 (6/18/14)	**Event Day 2 (8/27/14)**	**Event Day 3 (9/2/14)**
Hour	Event Day Impact	Event Day Impact	Event Day Impact
15	-26.8%	-17.1%	-23.5%
16	-25.2%	-20.1%	-24.9%
17	-20.2%	-13.3%	-27.8%
18	-22.5%	-9.4%	-29.0%
Average Impact	**-23.7%**	**-15.0%**	**-26.3%**
Average WTHI	**82.85**	**78.80**	**82.68**

Based on the results presented on Table 3, we found that the engaged PESC only customers reduced their peak period usage by 23.7% on Event Day 1; by 15% on Event Day 2; and by 26.3% on Event Day 3. Event Day 2 had the lowest WTHI and the lowest impact of the three event days. Event Days 1 and 3 had similar WTHI values, but the impact on Event Day 1 is lower than that on Event Day 3 as it was the first hottest day in the summer where the cooling load had not fully come online for the season. Therefore, hese results are consistent with our expectations.

V. System Impacts

The next step in our analysis was to take the estimated impacts and calculate what the energy and system peak reduction capability of the PESC program has been based on the engaged customer performance in the Summer of 2014.

A. Energy Reduction Capability

In order to calculate the energy reduction capability of the program, we first created a "but-for" load profile that represents what the average load of an engaged customer would be on an event day, if the event day had not been called. In order to calculate the but-for load, we have identified 26 non-event days with average peak WTHIs greater than or equal to 78 degrees[2]. Once we identified these days, we took the average load to create a but-for load profile for an event day in 2014. We further averaged the usage in the peak window (HE 15-18) of this load profile to create an average hourly peak period usage on a comparable non-event day.

In order to calculate the energy reduction capability of the PESC only program, we multiply the estimated percentage impacts with the but-for load times four and the number of engaged customers. We then gross-up this number for the residential loss factor for energy (1.0572), and obtain the energy reduction capability of the PESC program. Table 4 summarizes these results.

Table 4- 2014 PESC Program Energy Reduction Capability (MWh), PESC Only

Event Day	Avg. Peak WTHI	Engaged Customers	% Change in Peak	But-for Load (kW)	Energy Reduction Capability (MWh)
06/18/2014	82.9	149,966	-23.7%	2.3	-342.0
08/27/2014	78.8	249,858	-15.0%	2.3	-360.0
09/02/2014	82.7	190,401	-26.3%	2.3	-481.7
Average					**-394.6**

[2] We have selected 78 degrees as the threshold level, because the mildest event day in 2014 (Event Day 2) had an average peak WTHI of 78.8 degrees.

B. SYSTEM PEAK REDUCTION CAPABILITY

We have used PJM's system peak definition for Pepco MD service territory (HE 17 at 83.7 degrees) and selected July 2, 2014, a PJM designated system peak day for the Pepco Zone, to create our but-for load profile for the peak reduction capability calculations. We took the average of customer load profiles on July 2nd, and reported HE 17 load as our but-for load.

Next, we multiply the but-for load with the peak reduction impact evaluated at 83.7 degrees and the number of engaged customers. We then gross-up this number for the residential loss factor for peak (1.0963), and obtain the system peak reduction capability of the PESC program. Table 5 summarizes these results.

Table 5- 2014 PESC Program System Peak Reduction Capability (MW), PESC Only (HE 17 at WTHI=83.7)

Event Day	HE 17 WTHI	Engaged Customers	% Change in HE 17 Usage	HE 17 But-for Load (kW)	Peak Reduction Capability (MW)
06/18/2014	83.7	149,966	-20.6%	2.9	-97.2
08/27/2014	83.7	249,858	-14.1%	2.9	-110.6
09/02/2014	83.7	190,401	-28.0%	2.9	-168.1
Average					-125.3

VI. Conclusion

In this study, we have determined the energy and system peak reduction capability of the PESC program based on the performance of the customers who have engaged in the program in the summer of 2014. Comparing these results to the similar results from the 2013 PESC program, we conclude that the PESC program results have been fairly consistent across the two summers. The performance of the programs may increase further if the number of engaged customers increase in the future.

APPENDIX A- ESTIMATION RESULTS

Table A.1: 2014 PESC Only, Engaged Customers, Event Day 1

VARIABLES	(1) Hour 15	(2) Hour 16	(3) Hour 17	(4) Hour 18
Event Day 1 x WTHI	-0.00322***	-0.00305***	-0.00246***	-0.00271***
	(2.30e-05)	(2.19e-05)	(2.17e-05)	(2.24e-05)
WTHI	0.111***	0.200***	0.315***	0.226***
	(0.00236)	(0.00249)	(0.00263)	(0.00275)
WTHI^2	-0.000307***	-0.000882***	-0.00164***	-0.00105***
	(1.55e-05)	(1.62e-05)	(1.70e-05)	(1.79e-05)
Constant	-6.848***	-10.26***	-14.55***	-11.08***
	(0.0900)	(0.0957)	(0.101)	(0.106)
Observations	12,264,055	12,263,821	12,265,663	12,262,583
R-squared	0.117	0.119	0.112	0.105
Number of servicepointid	149,966	149,967	149,967	149,967

Robust standard errors in parentheses
*** p<0.01, ** p<0.05, * p<0.1

Table A.2: 2014 PESC Only, Engaged Customers, Event Day 2

VARIABLES	(1) Hour 15	(2) Hour 16	(3) Hour 17	(4) Hour 18
Event Day 2 x WTHI	-0.00219***	-0.00254***	-0.00168***	-0.00119***
	(1.61e-05)	(1.57e-05)	(1.56e-05)	(1.58e-05)
WTHI	0.0628***	0.174***	0.327***	0.236***
	(0.00187)	(0.00197)	(0.00206)	(0.00214)
WTHI^2	8.87e-05***	-0.000627***	-0.00163***	-0.00104***
	(1.23e-05)	(1.29e-05)	(1.34e-05)	(1.39e-05)
Constant	-5.393***	-9.655***	-15.39***	-11.86***
	(0.0711)	(0.0755)	(0.0794)	(0.0820)
Observations	20,535,624	20,535,351	20,538,547	20,531,005
R-squared	0.163	0.168	0.160	0.149
Number of servicepointid	249,858	249,858	249,858	249,858

Robust standard errors in parentheses
*** p<0.01, ** p<0.05, * p<0.1

Table A.3: 2014 PESC Only, Engaged Customers, Event Day 3

VARIABLES	(1) Hour 15	(2) Hour 16	(3) Hour 17	(4) Hour 18
Event Day 3 x WTHI	-0.00285***	-0.00301***	-0.00335***	-0.00351***
	(1.93e-05)	(1.91e-05)	(1.90e-05)	(1.94e-05)
WTHI	0.139***	0.240***	0.386***	0.299***
	(0.00207)	(0.00219)	(0.00231)	(0.00240)
WTHI^2	-0.000439***	-0.00110***	-0.00206***	-0.00148***
	(1.36e-05)	(1.42e-05)	(1.49e-05)	(1.56e-05)
Constant	-8.115***	-12.01***	-17.47***	-14.04***
	(0.0790)	(0.0840)	(0.0891)	(0.0922)
Observations	15,631,602	15,631,228	15,632,618	15,626,252
R-squared	0.147	0.150	0.141	0.131
Number of servicepointid	190,401	190,401	190,401	190,401

Robust standard errors in parentheses
*** p<0.01, ** p<0.05, * p<0.1

PLC-2

POTOMAC ELECTRIC POWER COMPANY
MARYLAND CASE NO. 9418
RESPONSE TO AOBA DATA REQUEST NO. 1

QUESTION NO. 1

PLEASE PROVIDE COMPLETE COPIES OF ALL RESPONSES TO DATA REQUESTS PROVIDED BY PEPCO IN RESPONSE TO DATA REQUESTS SUBMITTED TO THE COMPANY BY STAFF AND OTHER PARTIES.

RESPONSE:

All responses and supporting documentation will be accessible through a web-based document management service – eBridge. Please contact either Douglas Micheel at 202-872-2318 or Matthew Segers at 202-872-3484 to obtain access.

SPONSOR: The Company

Table of Contents

Pepco MD - Electric
Levelized Annual Carrying Charge Rate Calculations
(Avoided T&D assets)

Revenue Requirement Schedule

	Rate Base Calculation						Revenue Requirement Calculaton					Validation of Revenue Requirements- Income Statement											
PERIOD	Gross Plant	Accumulated Book Depreciation	Net Plant	Cummulative Deferred Tax	YR END RATE BASE	AVG RATE BASE	Return ON AVG RATE BASE	BOOK DEPR	Insurance	Operating Income	Revenue Requirement	Revenue	Depreciation	Insurance	Gross Receipt Tax	Earnings Before Taxes and Interest	Interest	Earnings Before Taxes	State Tax	Federal Tax	Net Income'	Net Income (WACC)	ROE - Check
					$100,000																		
1	$100,000	2,272.73	$97,727	596.26	97,131	$98,566	$6,797	$2,273	27	($1,371)	$13,976	$13,976	($2,273)	($27)	($280)	$11,397	($2,720)	$8,677	($716)	($2,786)	$5,175	$5,175	10.60%
2	$100,000	4,545.45	$95,455	2,592.70	92,862	$94,996	$6,551	$2,273	27	($1,372)	$13,556	$13,556	($2,273)	($27)	($271)	$10,985	($2,622)	$8,363	($690)	($2,685)	$4,987	$4,987	10.60%
3	$100,000	6,818.18	$93,182	4,370.38	88,811	$90,837	$6,264	$2,273	28	($1,372)	$13,065	$13,065	($2,273)	($28)	($261)	$10,504	($2,507)	$7,997	($660)	($2,568)	$4,769	$4,769	10.60%
4	$100,000	9,090.91	$90,909	5,946.24	84,963	$86,887	$5,992	$2,273	28	($1,372)	$12,600	$12,600	($2,273)	($28)	($252)	$10,047	($2,398)	$7,649	($631)	($2,456)	$4,562	$4,562	10.60%
5	$100,000	11,363.64	$88,636	7,334.82	81,302	$83,132	$5,733	$2,273	29	($1,373)	$12,157	$12,157	($2,273)	($29)	($243)	$9,613	($2,294)	$7,318	($604)	-	-	$4,364	10.60%
6	$100,000	13,636.36	$86,364	8,550.65	77,813	$79,557	$5,486	$2,273	29	($1,373)	$11,736	$11,736	($2,273)	($29)	($235)	$9,199	($2,196)	$7,004	($578)	($2,249)	$4,177	$4,177	10.60%
7	$100,000	15,909.09	$84,091	9,606.24	74,485	$76,149	$5,251	$2,273	30	($1,373)	$11,335	$11,335	($2,273)	($30)	($227)	$8,805	($2,102)	$6,704	($553)	($2,153)	$3,998	$3,998	10.60%
8	$100,000	18,181.82	$81,818	10,514.10	71,304	$72,894	$5,027	$2,273	31	($1,374)	$10,951	$10,951	($2,273)	($31)	($219)	$8,429	($2,012)	$6,417	($529)	($2,061)	$3,827	$3,827	10.60%
9	$100,000	20,454.55	$79,545	11,397.75	68,148	$69,726	$4,808	$2,273	31	($1,374)	$10,578	$10,578	($2,273)	($31)	($212)	$8,063	($1,924)	$6,138	($506)	($1,971)	$3,661	$3,661	10.60%
10	$100,000	22,727.27	$77,273	12,280.99	64,992	$66,570	$4,591	$2,273	32	($1,374)	$10,206	$10,206	($2,273)	($32)	($204)	$7,698	($1,837)	$5,860	($483)	($1,882)	$3,495	$3,495	10.60%
11	$100,000	25,000.00	$75,000	13,164.63	61,835	$63,414	$4,373	$2,273	32	($1,375)	$9,834	$9,834	($2,273)	($32)	($197)	$7,333	($1,750)	$5,582	($461)	($1,793)	$3,329	$3,329	10.60%
12	$100,000	27,272.73	$72,727	14,047.87	58,679	$60,257	$4,155	$2,273	33	($1,375)	$9,463	$9,463	($2,273)	($33)	($189)	$6,968	($1,663)	$5,305	($438)	($1,703)	$3,164	$3,164	10.60%
13	$100,000	29,545.45	$70,455	14,931.52	55,523	$57,101	$3,938	$2,273	34	($1,376)	$9,091	$9,091	($2,273)	($34)	($182)	$6,603	($1,576)	$5,027	($415)	($1,614)	$2,998	$2,998	10.60%
14	$100,000	31,818.18	$68,182	15,814.76	52,367	$53,945	$3,720	$2,273	34	($1,376)	$8,719	$8,719	($2,273)	($34)	($174)	$6,238	($1,489)	$4,749	($392)	($1,525)	$2,832	$2,832	10.60%
15	$100,000	34,090.91	$65,909	16,698.41	49,211	$50,789	$3,502	$2,273	35	($1,376)	$8,348	$8,348	($2,273)	($35)	($167)	$5,873	($1,402)	$4,471	($369)	($1,436)	$2,666	$2,666	10.60%
16	$100,000	36,363.64	$63,636	17,581.65	46,055	$47,633	$3,285	$2,273	36	($1,377)	$7,976	$7,976	($2,273)	($36)	($160)	$5,508	($1,315)	$4,193	($346)	($1,347)	$2,501	$2,501	10.60%
17	$100,000	38,636.36	$61,364	18,465.29	42,898	$44,477	$3,067	$2,273	37	($1,377)	$7,604	$7,604	($2,273)	($37)	($152)	$5,143	($1,228)	$3,915	($323)	($1,257)	$2,335	$2,335	10.60%
18	$100,000	40,909.09	$59,091	19,348.53	39,742	$41,320	$2,849	$2,273	37	($1,378)	$7,233	$7,233	($2,273)	($37)	($145)	$4,778	($1,140)	$3,638	($300)	($1,168)	$2,169	$2,169	10.60%
19	$100,000	43,181.82	$56,818	20,232.18	36,586	$38,164	$2,632	$2,273	38	($1,378)	$6,861	$6,861	($2,273)	($38)	($137)	$4,413	($1,053)	$3,360	($277)	($1,079)	$2,004	$2,004	10.60%
20	$100,000	45,454.55	$54,545	21,115.42	33,430	$35,008	$2,414	$2,273	39	($1,379)	$6,489	$6,489	($2,273)	($39)	($130)	$4,048	($966)	$3,082	($254)	($990)	$1,838	$1,838	10.60%
21	$100,000	47,727.27	$52,273	21,098.58	31,174	$32,302	$2,228	$2,273	40	($1,379)	$6,171	$6,171	($2,273)	($40)	($123)	$3,735	($892)	$2,844	($235)	($913)	$1,696	$1,696	10.60%
22	$100,000	50,000.00	$50,000	20,181.25	29,819	$30,496	$2,103	$2,273	40	($1,379)	$5,959	$5,959	($2,273)	($40)	($119)	$3,526	($842)	$2,685	($221)	($862)	$1,601	$1,601	10.60%
23	$100,000	52,272.73	$47,727	19,263.92	28,463	$29,141	$2,010	$2,273	41	($1,380)	$5,799	$5,799	($2,273)	($41)	($116)	$3,370	($804)	$2,565	($212)	($824)	$1,530	$1,530	10.60%
24	$100,000	54,545.45	$45,455	18,346.59	27,108	$27,786	$1,916	$2,273	42	($1,380)	$5,640	$5,640	($2,273)	($42)	($113)	$3,213	($767)	$2,446	($202)	($785)	$1,459	$1,459	10.60%
25	$100,000	56,818.18	$43,182	17,429.26	25,753	$26,430	$1,823	$2,273	43	($1,381)	$5,481	$5,481	($2,273)	($43)	($110)	$3,056	($729)	$2,327	($192)	($747)	$1,388	$1,388	10.60%
26	$100,000	59,090.91	$40,909	16,511.93	24,397	$25,075	$1,729	$2,273	44	($1,381)	$5,322	$5,322	($2,273)	($44)	($106)	$2,899	($692)	$2,207	($182)	($709)	$1,316	$1,316	10.60%
27	$100,000	61,363.64	$38,636	15,594.60	23,042	$23,719	$1,636	$2,273	45	($1,382)	$5,163	$5,163	($2,273)	($45)	($103)	$2,743	($655)	$2,088	($172)	($671)	$1,245	$1,245	10.60%
28	$100,000	63,636.36	$36,364	14,677.27	21,686	$22,364	$1,542	$2,273	45	($1,382)	$5,004	$5,004	($2,273)	($45)	($100)	$2,586	($617)	$1,969	($162)	($632)	$1,174	$1,174	10.60%
29	$100,000	65,909.09	$34,091	13,759.94	20,331	$21,009	$1,449	$2,273	46	($1,383)	$4,845	$4,845	($2,273)	($46)	($97)	$2,429	($580)	$1,849	($153)	($594)	$1,103	$1,103	10.60%
30	$100,000	68,181.82	$31,818	12,842.61	18,976	$19,653	$1,355	$2,273	47	($1,384)	$4,686	$4,686	($2,273)	($47)	($94)	$2,273	($542)	$1,730	($143)	($556)	$1,032	$1,032	10.60%
31	$100,000	70,454.55	$29,545	11,925.28	17,620	$18,298	$1,262	$2,273	48	($1,384)	$4,527	$4,527	($2,273)	($48)	($91)	$2,116	($505)	$1,611	($133)	($517)	$961	$961	10.60%
32	$100,000	72,727.27	$27,273	11,007.95	16,265	$16,942	$1,168	$2,273	49	($1,385)	$4,368	$4,368	($2,273)	($49)	($87)	$1,959	($468)	$1,491	($123)	($479)	$889	$889	10.60%
33	$100,000	75,000.00	$25,000	10,090.63	14,909	$15,587	$1,075	$2,273	50	($1,385)	$4,209	$4,209	($2,273)	($50)	($84)	$1,802	($430)	$1,372	($113)	($441)	$818	$818	10.60%
34	$100,000	77,272.73	$22,727	9,173.30	13,554	$14,232	$981	$2,273	51	($1,386)	$4,051	$4,051	($2,273)	($51)	($81)	$1,646	($393)	$1,253	($103)	($402)	$747	$747	10.60%
35	$100,000	79,545.45	$20,455	8,255.97	12,199	$12,876	$888	$2,273	52	($1,387)	$3,892	$3,892	($2,273)	($52)	($78)	$1,489	($355)	$1,134	($94)	($364)	$676	$676	10.60%
36	$100,000	81,818.18	$18,182	7,338.64	10,843	$11,521	$794	$2,273	53	($1,387)	$3,733	$3,733	($2,273)	($53)	($75)	$1,332	($318)	$1,014	($84)	($326)	$605	$605	10.60%
37	$100,000	84,090.91	$15,909	6,421.31	9,488	$10,165	$701	$2,273	54	($1,388)	$3,574	$3,574	($2,273)	($54)	($71)	$1,175	($281)	$895	($74)	($287)	$534	$534	10.60%
38	$100,000	86,363.64	$13,636	5,503.98	8,132	$8,810	$608	$2,273	55	($1,388)	$3,415	$3,415	($2,273)	($55)	($68)	$1,019	($243)	$776	($64)	($249)	$463	$463	10.60%
39	$100,000	88,636.36	$11,364	4,586.65	6,777	$7,455	$514	$2,273	56	($1,389)	$3,256	$3,256	($2,273)	($56)	($65)	$862	($206)	$656	($54)	($211)	$391	$391	10.60%
40	$100,000	90,909.09	$9,091	3,669.32	5,422	$6,099	$421	$2,273	58	($1,390)	$3,098	$3,098	($2,273)	($58)	($62)	$705	($168)	$537	($44)	($172)	$320	$320	10.60%
41	$100,000	93,181.82	$6,818	2,751.99	4,066	$4,744	$327	$2,273	59	($1,390)	$2,939	$2,939	($2,273)	($59)	($59)	$549	($131)	$418	($34)	($134)	$249	$249	10.60%
42	$100,000	95,454.55	$4,545	1,834.66	2,711	$3,388	$234	$2,273	60	($1,391)	$2,780	$2,780	($2,273)	($60)	($56)	$392	($94)	$298	($25)	($96)	$178	$178	10.60%
43	$100,000	97,727.27	$2,273	917.33	1,355	$2,033	$140	$2,273	61	($1,392)	$2,621	$2,621	($2,273)	($61)	($52)	$235	($56)	$179	($15)	($57)	$107	$107	10.60%
44	$100,000	100,000.00	($0)	0.00	0	$678	$47	$2,273	62	($1,393)	$2,463	$2,463	($2,273)	($62)	($49)	$78	($19)	$60	($5)	($19)	$36	$36	10.60%
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PLC-2

	Rate Base Calculation						Revenue Requirement Calculaton					Validation of Revenue Requirements- Income Statement											
PERIOD	Gross Plant	Accuumlated Book Depreciation	Net Plant	Cummulative Deferred Tax	YR END RATE BASE	AVG RATE BASE	Return ON AVG RATE BASE	BOOK DEPR	Insurance	Operating Income	Revenue Requirement	Revenue	Depreciation	Insurance	Gross Receipt Tax	Earnings Before Taxes and Interest	Interest	Earnings ‹efore Taxe	State Tax	Federal Tax	Net Income'	Net Income (WACC)	ROE - Check
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NPV of Revenue Requirement	$119,364
Levalized Annual Payments	$9,895
Carrying Charge	9.89%

Energy Price Mitigation Working Papers

Pepco conducted a regression analysis of PJM Maryland zonal hourly Location Marginal Pricing (LMP) of energy to the corresponding hourly load in Maryland for each Maryland utility zone (Potomac Edison, BGE, Pepco (including SMECO) and Delmarva Power). The selected time period for the regression analysis was for pricing and load data starting on January 1 2013 and ending August 31 2015. Four time-of-use time periods were selected and a load weighted average price was determined for each time period. The hourly load data was then used to determine an average load for each time period for each zone. A load weighted[1] price of energy was than calculated for each of the four zones in Maryland, and the four time periods for each zone. A regression model was run for each zone to determine the change in price resulting from a one percent change in load. The electricity cost impact was then determined by multiplying the price change times the residual load.

Step by Step Work Process Flow

First Work Process: Compile hourly load data for all four Zones by time period in Maryland.

1. Developed and allocate the data across the four time periods, based on PJM definitions:
    - Summer On Peak, Summer Off Peak, Non-summer On Peak, Non-Summer Off Peak
    - The hourly loads were split into on and off-peak periods as defined by NERC. On-peak is hour ending (HE) 8 through HE 23, Monday – Friday excluding holidays. Off-peak is HE 1 through 7 and HE 24, Monday – Friday, all day Saturday, all day Sunday and all day on NERC holidays.

    - The NERC holidays are:

	2013	2014	2015
New Year's Day	01/01/2013	01/01/2014	01/01/2015
Memorial Day	05/27/2013	05/26/2014	05/25/2015
Independence Day	07/04/2013	07/04/2014	07/04/2013
Labor Day	09/02/2013	09/01/2014	09/07/2015
Thanksgiving	11/28/2013	11/27/2014	11/26/2015
Christmas	12/25/2013	12/25/2014	12/25/2015

2. Apply the Maryland utility share of each of the four PJM Zones in Maryland. APS 17%, BGE 100%, Pepco 61.9% (includes SMECO), DPL 31%.

3. Determine the hourly load by the residual Maryland share of zone load

[1] Load was assigned to the portion the Maryland portion of the PJM utility zones based upon the most recently available PJM BRA 2018/2019 Load Pricing Results.

4. Calculate the average of the loads by the four time periods.

5. Calculate the indexed load for the four periods.

   The indexed load is defined as the actual hourly load divided by the average load over each of the four periods (same formula applies to the indexed prices).

Second Work Process: Read in hourly price data for all four Zones and periods in Maryland.

1. Read in the hourly prices by zone

2. Compile the data into the four time periods.

3. Apply the load weights (calculated outside the SAS program) to the hourly prices by zone.

4. Sum prices across the four zones by the four time periods.

5. Calculate the average of the prices by four periods

6. Calculate the indexed price (load for hour/avg. load for four periods.

Third Work Process: Merge the indexed loads and indexed prices by four periods.

1. The indexed price for each bin was calculated and merged with the indexed loads by the four time periods.

2. Calculate the Maryland load weighted average, based on the load and price in each of the resulting sixteen specific Maryland time periods (four zones x four time periods).

Fourth Work Process: Perform the regressions.

A regression model was run to determine the relationship between price and load for each period and each utility zone. Index prices were estimated on an hourly basis.

Regression formula:

$$IP_t = \beta_0 + \beta_1 * IL_t$$

Where, IP_t is the Indexed Price for time *t* and IL_t is the Indexed load for time *t*. *(Indexed prices were estimated on an hourly basis).*

Maryland Aggregated Load Weighted Regression Results:

For each 1% reduction in load, prices decrease by the following amount: (Note: these are from the All Sourced Zones, not individual Zones as represented in the dollars figures further below).

- Summer On Peak: 1.6672%
- Summer Off Peak: 1.6128%
- Non-Summer On Peak: 4.5792%
  Non-Summer Off Peak: 3.1338%

Fifth Work Process: The calculation to derive the estimated energy capacity price mitigation of $1.42 per MWh of AMI savings.

The 1% load reduction parameter estimate has been further adjusted to reflect the proportion of Pepco AMI savings to all Maryland load. The adjusted parameter estimates were then applied to residual average energy load and average price for each time period to yield the estimates savings in a given year. This total amount of annual savings in energy mitigation across Maryland is then divided by the total Pepco annual AMI MWhs of savings in a specific year to determine the avoided energy price mitigation value per MWh of AMI savings each year. This value is approximately $1.42 per AMI reported MWh of savings.

The formula is: $1.42/ MWh of AMI Savings = (Pepco AMI Savings/Residual Maryland Sales) x (Parameter Estimate) x (Price) x Residual Maryland Sales) / Pepco AMI Savings

MARYLAND SUBSTATION LOADS AND PROJECTS FROM 2014 - 2023 TEN YEAR FORECAST

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Predicted Pepco Maryland Load in MVA	3533.1	3592.8	3645.8	3700.5	3748.3	3789.0	3831.8	3877.5	3915.8	3945.1
Load growth/year in MVA		59.7	53.0	54.7	47.8	40.7	42.8	45.7	38.3	29.3
total load growth over 10 year period --->										412.0

Substation Projects	Increase in Capacity	In-Service Date	Cost
Replace 20 MVA with 30 MVA transformer at Kingswood Sub. 85	10	2016	$ 4,539,004
Install 30 MVA transformer at Colesville Sub. 44	40	2016	$ 8,574,174
Construct Darnestown Road Sub. 225	40	2017	$ 28,995,292
Construct Grosvenor Sub. 229	40	2018	$ 43,320,185
Construct Melwood Sub. 224	40	2020	$ 24,239,000
total	170		$ 109,667,655

a	load growth over 10 year period (MVA)	412.0	
b	distribution capacity added over 10 year period (MVA)	170	
c	cost to add distribution capacity over 10 year period	$ 109,667,655	
d	$/MW to add distribution capacity	$ 645,104	d = c / b
f	Capacity Required/Load Growth Factor	0.41	f = b / a
g	$/MW of load growth	$ 266,184	g = d * f
h	**$/KW of load growth**	**$ 266**	h = g / 1000
i	$/MW-Yr	$ 26,352	I = g * .099
j	$/MW-day	$ 72.20	j = I / 365

Pepco MD Avoided Transmission and Distribution Costs

Calculation of Transmission & Distribution Avoided Cost	Pepco *		
Cost to add distribution capacity ($/MW)	$	521,992	Calculation 1
Distribution capacity/demand ratio		0.33	Calculation 2
Avoided Distribution Cost ($/MW)	$	172,257	
MW/Year (9.9% carrying charge)	$	17,053	
Avoided Distribution Cost ($/MW-Day)	**$**	**46.72**	
Cost to add sub-transmission capacity($/MW)	$	35,789	Calculation 3
Sub-transmission capacity/demand ratio		0.93	Calculation 2
Avoided sub-transmission Cost ($/MW)	$	33,284	
MW/Year (9.9% carrying charge)	$	3,295	
Avoided Sub-transmission Cost ($/MW-Day)	**$**	**9.03**	
Total Distribution (including sub-transmission) $/MW	$	205,541	
MW/Year (9.9% carrying charge)	$	20,349	
Avoided Distribution Cost (including sub-transmission) ($/MW-Day)	**$**	**55.75**	

Transmission Cost ($/MW) (using CETL)	$	467,737	Calculation 4
MW/Year (9.9% carrying charge)	$	46,306	
Avoided Transmission Cost ($/MW-Day)	**$**	**126.87**	

Avoided Cost - Total T & D - $/MW	**$**	**673,278**
Avoided Cost - Total T & D - MW/Year (9.9% carrying charge)	**$**	**66,655**
Avoided Cost - Total T & D - $/MW-Day	**$**	**182.62**

*** Excludes land cost for substations**

Calculation 1:

Avoided Distribution Cost - Pepco **			
Substation	**Capacity (MVA)**	**TOTAL COST**	
Darnestown	40	$	28,746,843
Melwood	40	$	19,423,030
Grosvenor	40	$	51,385,600
Average cost of a New Substation	40	**$**	**33,185,158**
Colesville 3rd transformer	40	$	8,574,174
Average cost of a full Substation	80	**$**	**41,759,332**
Average $/MW		$	**521,992**

**** Distribution cost above were pulled out of PPM for planned distribution substation additions**

Calculation 2:

PEPCO 15-year Ratio Calculation (1998-2013)	
Maryland Peak load 2013 (MW)	3,767
Maryland Peak load 1998 (MW)	3,154
15 year increment in Maryland Peak load (MW)	613
15 years added distribution capacity (MW)	205
Distribution capacity/demand ratio	**0.33**
15 years added sub-transmission capacity (MW)	570
Sub-transmission capacity/demand ratio	**0.93**

Calculation 3:

Avoided Sub-transmission Cost - Pepco ***				
	Capacity (MVA)	**Cost to add a 3rd 230/69kV transformer**	**Cost to add two 230kV breakers**	**TOTAL COST**
Additional Generic Transformer	285	$ 7,900,000	$ 2,300,000	$ 10,200,000
Average $/MW				$ **35,789**

*****Sub-transmission cost are from TYF cost estimating data**

Calculation 4:

Avoided Transmission Cost - Pepco		
Cost to Replace Import Capability	$	2,096,863,000
CETL 2013/14 (MW) ****		4,483
$/MW using peak demand	$	**467,737**

****** Capacity Emergency Transfer Limit as established by PJM for the Pepco zone as published in PJM BRA 2013/2014 Planning Parameters issued 5/17/2010**

POTOMAC ELECTRIC POWER COMPANY
MARYLAND CASE NO. 9418
RESPONSE TO OPC DATA REQUEST NO. 8

QUESTION NO. 2

PLEASE REFERENCE THE DIRECT TESTIMONY OF GIOVANNINI, P. 3 REGARDING AMI METERING. PLEASE PROVIDE HOURLY CLASS LOAD FROM THE AMI METERING INFORMATION SINCE JUNE 1, 2013.

RESPONSE:

Please refer to OPC DR 8-2 Attachment provided electronically only.

SPONSOR: Mario Giovannini

POTOMAC ELECTRIC POWER COMPANY
MARYLAND CASE NO. 9418
RESPONSE TO OPC DATA REQUEST NO. 8

QUESTION NO. 3

PLEASE REFERENCE THE DIRECT TESTIMONY OF GIOVANNINI, P. 7 AT 9–12:

A. PLEASE PROVIDE A BREAKDOWN OF PEPCO'S CLEARED DR CAPACITY AND EE CAPACITY IN EACH DELIVERY YEAR 2013/14 TO 2019/20, IDENTIFYING THE CLEARED CAPACITY (MW) FOR EACH PEPCO PROGRAM.

B. FOR EACH PEPCO DR PROGRAM, PLEASE IDENTIFY WHETHER THE PROGRAM CLEARED AS AN ANNUAL, LIMITED OR EXTENDED SUMMER RESOURCE, FOR EACH YEAR THROUGH DY 2017/18.

C. FOR EACH PEPCO DR PROGRAM CLEARED FOR DY 2016/17 OR DY 2017/18, PLEASE IDENTIFY WHETHER THE PROGRAM CLEARED AS CAPACITY PERFORMANCE IN THE SUBSEQUENT TRANSITION INCREMENTAL AUCTION.

D. FOR EACH PEPCO DR PROGRAM CLEARED IN BRAS FOR DY 2018/19 OR 2019/20, PLEASE IDENTIFY WHETHER THE PROGRAM CLEARED AS CAPACITY PERFORMANCE.

RESPONSE:

A.

Pepco MD
Cleared Capacity MW (UCAP), by Program

Delivery Year	Auction	DLC	DP	EE
2013/2014	BRA	124.1		18.6
	Net Position	134.3	28.0	52.6
2014/2015	BRA	175.2	192.2	32.6
	Net Position	159.2	142.2	40.3
2015/2016	BRA	189.9	175.5	46.6
	Net Position	179.9	152.5	86.6
2016/2017	BRA	149.9	173.7	73.4
	Net Position	169.7	173.7	125.4
2017/2018	BRA	142.6	159.9	83.1
	Net Position	173.7	159.9	83.1
2018/2019	BRA	178.8	162.5	36.7
	Net Position	178.8	162.5	36.7
2019/2020	BRA	177.0	162.5	47.4
	Net Position	177.0	162.5	47.4

B.

	Pepco MD Resource Type		
Delivery Year	**DLC**	**DP**	**EE**
2013/2014	Limited	Limited	Limited
2014/2015	Limited/Extended Summer	Limited	Annual
2015/2016	Extended Summer	Limited	Annual
2016/2017	Extended Summer	Extended Summer	Annual
2017/2018	Extended Summer	Extended Summer	Annual

Notes: In DY 2014/2015, 100% cycled DLC cleared as a limited resource. DLC cycled at 50% and 75% cleared as an extended summer resource.

C. Pepco DR programs were ineligible to participate in the DY 2016/17 and DY 2017/18 transition incremental auctions because they did not meet capacity performance standards. The transition incremental auctions were held to allow resources that qualified as capacity performance resources to clear as such. Please refer to Company Witness Giovannini's Direct Testimony on p. 8, lines 6 through 17.

D. No. Pepco DR programs that cleared in BRAs for DY 2018/19 and DY 2019/20 cleared as base capacity. Please refer to Company Witness Giovannini's Direct Testimony on p. 8, lines 6 through 17.

SPONSOR: Mario Giovannini

POTOMAC ELECTRIC POWER COMPANY
MARYLAND CASE NO. 9418
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QUESTION NO. 7

GIOVANNINI, PP. 7–8. DYNAMIC PRICING PROGRAM. PLEASE PROVIDE:

A. THE "VALUE OF ESTABLISHED BID POSITIONS" FOR THE DP PROGRAM BY DELIVERY YEAR.
B. ALL CALCULATIONS AND WORKSHEETS THAT WERE USED TO ESTIMATE ACTUAL LOAD REDUCTIONS THROUGH DYNAMIC PRICING.
C. THE MEASUREMENT ALGORITHM THAT PJM HAS APPROVED FOR PEPCO'S DP PROGRAM.
D. ALL SUBMISSIONS AND FILINGS IN WHICH PJM HAS DOCUMENTED AND/OR CLAIMED LOAD REDUCTIONS FOR THE DP PROGRAM.
E. ALL STUDIES USED TO ASSESS PEPCO CONSUMERS' RESPONSIVENESS TO DYNAMIC PRICING.
F. THE PRICE(S) OFFERED FOR LOAD REDUCTIONS IN THE DP PROGRAM.
G. A LIST OF EACH PEAK SAVINGS DAY, AND FOR EACH:
   I. THE HOURS FOR WHICH THE INCENTIVE WAS COMPUTED,
   II. THE LEAD TIME FOR NOTIFICATION OF CUSTOMERS OF THE PEAK SAVINGS DAY.

RESPONSE:

A. Please refer to the Company's response to Staff DR 6-1, Attachment C, Dynamic Pricing Benefits Tab. The Dynamic Pricing Program reductions recently cleared in the 2019/20 May 2016 auction at $595. This market position was established occurred after Witness Giovannini's Testimony was filed.

B. Assuming that this is referring to use of regression modeling, please refer to the response to OPC DR 8-21.

C. **Load Management Event Compliance (Prior to 2018/2019 Delivery Year)**

The load reduction is calculated hourly and then averaged across all hours of the event.

Reduction (MW) = Peak Load Contribution – (Metered Load * Capacity Loss Factor)
Resource complies if Reduction MW (ICAP) >= Committed MW (ICAP)

Compliance is averaged over the hours the resource was dispatched for at least 30 minutes of the clock hour during the event. The capacity commitment for the partial dispatch compliance hour will be prorated based on the number of minutes dispatched during the clock hour.

Non-Performance Assessment (2018/2019 and 2019/2020 Delivery Years)

For purposes of the Non-Performance Assessment for demand resources, compliance will be measured in a similar manner as the load management event compliance described above except that compliance will be measured for each hour as opposed to being averaged across all hours of an event.

D. PJM verifies load reductions by reviewing the hourly load data submitted by Pepco after an event to ensure that the RPM capacity commitment was met. Please refer to OPC DR 8-7d Attachment provided electronic only.

E. Refer to OPC DR 8-7e Attachment and the response to OPC DR 3-8.

F. Pepco offered load reductions from the DP program into the PJM capacity auctions as a price taker to avoid setting the marginal unit price.

G. Please refer to OPC DR 8-7g Attachment.

SPONSOR: Mario Giovannini

PLC-2

POTOMAC ELECTRIC POWER COMPANY
MARYLAND CASE NO. 9418
RESPONSE TO OPC DATA REQUEST NO. 8

QUESTION NO. 8

PLEASE REFERENCE THE DIRECT TESTIMONY OF GIOVANNINI, P. 9 AT 8–9. PROVIDE ALL ANALYSES AND SUPPORTING WORKPAPERS USED TO ASSESS DEMAND REDUCTIONS FROM PEPCO'S DP PROGRAM THAT CONTINUE IN THE ABSENCE OF PJM CAPACITY MARKET REVENUE BY YEAR.

RESPONSE:

Please refer to Staff DR 6-1, Attachment C, Dynamic Pricing Tab.

SPONSOR: Mario Giovannini

POTOMAC ELECTRIC POWER COMPANY
MARYLAND CASE NO. 9418
RESPONSE TO OPC DATA REQUEST NO. 8

QUESTION NO. 9
PLEASE REFERENCE THE DIRECT TESTIMONY OF GIOVANNINI, P. 9, OPTIONS (1) TO (3). PLEASE EXPLAIN HOW PEPCO IMAGINES EACH OF THESE POTENTIAL PROGRAMS OPERATING, AND FOR EACH PROGRAM:

A. EXPLAIN HOW THE EVENT DAYS (OR PEAK SAVINGS DAYS) AND HOURS WOULD BE DETERMINED.
B. EXPLAIN HOW THE PROGRAM WOULD BE JUSTIFIED IF IT DID NOT RECEIVE ANY PJM CAPACITY CREDIT.

RESPONSE:

Pepco has identified the following options for discussion purposes, however these options or others should be considered through a Maryland stakeholder process. Note that the future PJM market structure and associated rules are also likely to be modified over time and these changes will influence the manner that demand response programs should be designed and operate in Maryland.

Option 1 – Demand Response Portfolio Standard – All electricity suppliers would be required to match a percentage of their peak electric load sales in Maryland with Maryland sourced demand response resources. The price of the Maryland sourced demand resources could be established through a competitive bid process or via a Commission established pricing schedule.

Option 2 – Funding via the EmPOWER Surchage – The dynamic pricing credit funding could be provided through the existing EmPOWER Surcharge.

Option 3 – Pepco's existing dynamic pricing could be modified from a bill rebate program to a critical peak pricing program, whereby prices would be higher during peak event hours and lower during other hours.

A. The selection of peak event days would be based upon one or more of the following factors: 1) PJM day ahead energy prices, 2) forecast regional electricity loads, 3) PJM and distribution system emergency conditions, and 4) temperature and humidity conditions.

B. The program would be justified by avoided capacity and energy costs, capacity and energy price mitigation, air emissions reductions, deferring/avoiding additional transmission and distribution projects, helping to ensure the continuing reliability of electricity supply during high load periods, achieving Maryland demand reduction goals, and motivating Pepco Maryland customers to lower their electricity use and their resulting electric bills.

SPONSOR: Mario Giovannini

POTOMAC ELECTRIC POWER COMPANY
MARYLAND CASE NO. 9418
RESPONSE TO OPC DATA REQUEST NO. 8

QUESTION NO. 10

PLEASE REFERENCE THE DIRECT TESTIMONY OF GIOVANNINI, P. 9 AT 21–22. PLEASE EXPLAIN HOW THE COSTS OF THE REBATES PAID TO INDUCE CUSTOMERS TO PARTICIPATE IN THE DP PROGRAM ARE ACCOUNTED FOR IN THE COST BENEFIT ANALYSIS.

RESPONSE:

The costs of customer bill credits or "rebates" are treated as a transfer payment in the Company's AMI cost-effectiveness analysis. The Commission recently affirmed this cost-effectiveness treatment in its BGE rate case Order No. 87591, p. 64.

SPONSOR: Mario Giovannini

POTOMAC ELECTRIC POWER COMPANY
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QUESTION NO. 24

PLEASE REFERENCE THE DIRECT TESTIMONY OF GIOVANNINI, P. 19, TABLE 3: PESC EVENT DAYS:

A. PLEASE CLARIFY WHETHER THE PESC PROGRAM EVENTS ARE THE SAME AS THE PEAK SAVINGS DAYS (GIOVANNINI, P. 7), AND IF NOT, HOW THOSE EVENTS DIFFER.
B. PLEASE INDICATE FOR EACH EVENT DATE IF IT WAS A PJM-CALLED EVENT, AND IF SO, THE TYPE OF PJM EVENT.
C. PLEASE PROVIDE ALL PJM EMERGENCY EVENTS CALLED BETWEEN 2013 AND 2015.
D. PLEASE PROVIDE FOR EACH EVENT DATE INDICATED, PLEASE PROVIDE HOURLY AMI INFORMATION FOR A FULL 48 HOURS STARTING 24 HOURS PRIOR TO THE EVENT DATE.
E. HOW WERE ENERGY REDUCTIONS MEASURED?
F. WHAT ARE THE REQUIREMENTS FOR ELIGIBILITY?
G. WHAT WERE THE CRITERIA USED TO DETERMINE IF A CUSTOMER PARTICIPATED?
H. WHERE ANY CUSTOMERS ENROLLED IN OTHER PEPCO DEMAND SIDE MANAGEMENT PROGRAMS? IF, SO, PLEASE INDICATE WHICH PROGRAM AND WHAT PORTION OF CUSTOMERS WERE ENROLLED.

RESPONSE:

A. They are the same.

B. There was one PJM called event on September 11, 2013.

C. There was one PJM called event on September 11, 2013.

D. Refer to the response provided to OPC DR 8-2.

E. Energy reductions in MWs are measured for each hour the program operates. The reductions are calculated using the default PJM "Customer Base Line" minus the metered load for each hour. More specific details of the calculation can be found in the PJM Open Access Transmission Tariff Section 3.3A.2.

F. All Pepco Maryland residential distribution customers with activated AMI meters are eligible to participate, as directed by the Commission through Order No. 83571.

G. A participant is defined as a customer who earned a PESC credit.

H. Please refer to the table below.

PESC Events	
Event Date	**EWR Eligible**
8/21/2013	112,857
9/11/2013	112,523
6/18/2014	113,765
8/27/2014	146,087
9/2/2014	145,589
7/21/2015	166,819
7/30/2015	166,926
8/3/2015	166,431
9/9/2015	164,445

Note: 2015 data sourced from billing system. 2013 and 2014 data sourced from load settlement system. Excludes 1 hour test event dates.

SPONSOR: Mario Giovannini

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Jurisdiction	Year	Date	Settlement Type	Reduction KWH	Pro Rata	Total Energy	Balancing Operating	Pro Rata Energy	Pro Rata Balancing	Net Energy Revenue
Pepco	**2013**	**9/11/2013**	**Emergency Energy**	**59319.98**	**0.92**	**$69,258.52**		**$11,024.66**	**$0.00**	**$11,024.66**
Pepco	2014	6/18/2014	Economic Energy	56415.53	0.13	$44,329.82		$5,755.59	$0.00	$5,755.59
Pepco	2014	8/27/2014	Economic Energy	80661.97	0.15	$33,755.55	$380.33	$5,171.08	$58.26	$5,112.82
Pepco	2014	9/2/2014	Economic Energy	68130.70	0.13	$33,755.55	$380.33	$4,367.73	$49.21	$4,318.52
Pepco	2015	7/21/2015	Economic Energy	59557.81	0.21	$12,269.20	$82.98	$2,632.00	$17.80	$2,614.20
Pepco	2015	7/30/2015	Economic Energy	429029.01	0.43	$33,183.99	$198.70	$14,376.79	$86.09	$14,290.71
Pepco	2015	9/9/2015	Economic Energy	109136.33	0.27	$20,820.28	$73.93	$5,718.96	$20.31	$5,698.66
										$48,815.16

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POTOMAC ELECTRIC POWER COMPANY
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QUESTION NO. 14

PLEASE REFERENCE THE DIRECT TESTIMONY OF GIOVANNINI, P. 12 AT 8–10:

A. PLEASE PROVIDE ALL DATA AND ANALYSIS USED TO ESTIMATE DEMAND REDUCTIONS DERIVED FROM THE DP PROGRAM BEGINNING JUNE 1, 2020.

B. PLEASE EXPLAIN HOW PEPCO ESTIMATED THE EXTENT TO WHICH THE DEMAND REDUCTIONS FROM THE DP PROGRAM WOULD AFFECT THE PEAK LOADS USED IN THE PJM LOAD-FORECASTING MODEL.

C. PLEASE EXPLAIN HOW PEPCO ESTIMATED THE EXTENT TO WHICH THE DP REDUCTION IN PEAK LOADS IN THE SUMMER OF 2020 WOULD AFFECT CAPACITY OBLIGATIONS IN THE PEPCO ZONE IN EACH YEAR FROM 2020 TO 2023.

D. PLEASE PROVIDE ALL DATA AND ANALYSIS USED TO ESTIMATE DEMAND REDUCTIONS DERIVED FROM THE CVR PROGRAM.

E. PLEASE EXPLAIN HOW PEPCO ESTIMATED THE EXTENT TO WHICH THE DEMAND REDUCTIONS FROM THE CVR PROGRAM WOULD AFFECT THE PEAK LOADS USED IN THE PJM LOAD-FORECASTING MODEL.

F. PLEASE EXPLAIN HOW PEPCO ESTIMATED THE EXTENT TO WHICH THE CVR REDUCTION IN PEAK LOADS IN THE SUMMER OF 2013 WOULD AFFECT CAPACITY OBLIGATIONS IN THE PEPCO ZONE IN EACH YEAR FORM 2013 TO 2023.

G. PLEASE PROVIDE ALL DATA AND ANALYSIS USED TO ESTIMATE DEMAND REDUCTIONS DERIVED FROM THE EMT PROGRAM.

H. PLEASE EXPLAIN HOW PEPCO ESTIMATED THE EXTENT TO WHICH THE DEMAND REDUCTIONS FROM THE EMT PROGRAM WOULD AFFECT THE PEAK LOADS USED IN THE PJM LOAD-FORECASTING MODEL.

I. PLEASE EXPLAIN HOW PEPCO ESTIMATED THE EXTENT TO WHICH THE EMT REDUCTION IN PEAK LOADS IN THE SUMMER OF 2017 WOULD AFFECT CAPACITY OBLIGATIONS IN THE PEPCO ZONE IN EACH YEAR FORM 2018 TO 2023.

RESPONSE:

A. Please refer to Staff DR 6-1, Attachment C, DP, Dynamic Pricing Benefits Tab.

B. Pepco has assumed that the DP Program will participate as a demand-side, rather than a supply-side resource in the PJM wholesale capacity market beginning with PJM Delivery Year 2020/21, if the current PJM capacity market rules remain unchanged. Due to the previous existence of the DP Program over numerous prior summer periods as a supply-side, the Company expects PJM to reflect the availability of this load reduction resource in its load forecast beginning with PJM Delivery Year 2020/21.

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C. Please refer to Staff DR 6-1, Attachment C, Dynamic Pricing Benefits Tab.

D. Please refer to the Direct Testimony of Company Witness Faruqui, Schedule (AF)-3 and to Staff DR 6-1, Attachment C, CVR Benefits Tab.

E. Pepco expects that the future PJM load forecasts will reflect peak demand reductions derived from the CVR Program four years after the reductions occur.

F. Please refer to Staff DR 6-1, Attachment C, CVR Benefits Tab. Pepco expects that capacity obligations will be reduced from what they otherwise would have been four years after the reductions occur.

G. Please refer to the Direct Testimony of Company Witness Faruqui, Schedule (AF)-2 and to Staff DR 6-1, Attachment C, EMT Benefits Tab.

H. Pepco expects that the future PJM load forecasts will reflect peak demand reductions derived from the EMT Program four years after the reductions occur.

I. Please refer to Staff DR 6-1, Attachment C, EMT Benefits Tab. Pepco expects that capacity obligations will be reduced from what they otherwise would have been four years after the reductions occur.

SPONSOR: Mario Giovannini

POTOMAC ELECTRIC POWER COMPANY
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QUESTION NO. 16

DOES MR. GIOVANNINI AGREE THAT THE DP, CVR AND EMT PROGRAMS REDUCE CAPACITY PRICES ONLY TO THE EXTENT THAT THEY REDUCE PJM'S FORECAST OF PEAK LOAD?

A. IF NOT, PLEASE EXPLAIN WHY, AND HOW ELSE MR. GIOVANNINI BELIEVES THE PROGRAMS AFFECT CAPACITY PRICES.

RESPONSE:

Yes, however it should be noted that through PJM Delivery Year 2019/20 Pepco's DP Program participates in the capacity market as a supply-side resource.

SPONSOR: Mario Giovannini

POTOMAC ELECTRIC POWER COMPANY
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QUESTION NO. 18

PLEASE REFERENCE THE DIRECT TESTIMONY OF GIOVANNINI, P. 15 AT 4-6, REFERENCING THE STATEMENT THAT "PEPCO'S CAPACITY PRICE MITIGATION ASSUMPTIONS ARE CONSISTENT WITH THE CAPACITY PRICE MITIGATION METHOD ESTABLISHED BY THE COMMISSION THROUGH ORDER NO. 87082, ISSUED ON JULY 16, 2015 IN CASE NO. 9155." PLEASE EXPLAIN HOW PEPCO ADAPTED THE CAPACITY PRICE MITIGATION METHOD TO REFLECT:

A. LOAD REDUCTIONS THAT DO NOT REDUCE PEAK LOADS.
B. LOAD REDUCTIONS THAT REDUCE ONLY A SMALL FRACTION OF HIGH-LOAD HOURS USED IN THE PJM LOAD FORECAST.
C. CLEARED RESOURCES THAT ARE NOT ANNUAL RESOURCES (IN 2013/14 THROUGH 2017/18) OR CAPACITY PERFORMANCE RESOURCES (IN 2018/19 AND 2019/20).
D. RESOURCES WHOSE PARTICIPANT IN THE CAPACITY MARKET WAS LIMITED AND THAT CLEARED AT PRICES BELOW THE GENERAL CAPACITY PRICE IN THE ZONE.

RESPONSE:

A. Load reductions that do not reduce peak loads are not included.

B. This assumption is identical to that used in the EmPOWER Maryland proceeding. Note that EMT and CVR provide energy reductions across all load hours.

C. The Company has assumed that all cleared supply-side resources will have an effect on all wholesale capacity market prices. Suppliers are expected to adjust their price positions based upon the expected availability of all supply resources.

D. Please refer to the response to OPC DR 8-3, Parts A and B.

SPONSOR: Mario Giovannini

POTOMAC ELECTRIC POWER COMPANY
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RESPONSE TO OPC DATA REQUEST NO. 8

QUESTION NO. 19

HAS PEPCO REQUESTED THAT PJM ESTIMATE THE EFFECT OF THE DP, CVR AND EMT LOAD REDUCTIONS ON CAPACITY PRICES BY ZONE?

A. IS MR. GIOVANNINI FAMILIAR WITH THE PJM SENSITIVITY SCENARIOS FOR THE RPM AUCTIONS?

B. PLEASE EXPLAIN WHETHER PEPCO'S CAPACITY PRICE MITIGATION ASSUMPTIONS ARE CONSISTENT WITH PJM'S ESTIMATES OF THE EFFECTS OF CHANGING SUPPLY OR DEMAND, AS INDICATED BY THE SENSITIVITY SCENARIOS.

C. IF PJM'S ESTIMATE OF THE EFFECT OF CHANGING DEMAND ON CAPACITY PRICES IS DIFFERENT FROM PEPCO'S ESTIMATE BASED ON THE METHODOLOGY PEPCO USED IN CASE NO. 9155, WOULD MR. GIOVANNINI AGREE THAT PJM HAS THE GREATER KNOWLEDGE AND EXPERTISE REGARDING THE OPERATION OF THE CAPACITY MARKETS, AND HENCE THE PJM'S ESTIMATE IS MORE RELIABLE?

RESPONSE:

No.

A. Yes.

B. The Company has not performed this analysis.

C. The Company has relied upon the PJM established VRR curves to estimate the capacity price mitigation impact of demand reduction resources. The Commission specified the methodology for capacity mitigation estimates through Order No. 87082 in the EmPOWER proceeding. This methodology was reaffirmed by the Commission in its BGE rate case decision, Order No. 87591, p.61.

SPONSOR: Mario Giovannini

POTOMAC ELECTRIC POWER COMPANY
MARYLAND CASE NO. 9418
RESPONSE TO OPC DATA REQUEST NO. 8

QUESTION NO. 20

PLEASE REFERENCE THE DIRECT TESTIMONY OF GIOVANNINI, P. 15 AT 9-10, REFERENCING THE STATEMENT THAT "[T]HE CHANGE IN PRICE RESULTING FROM ADDITIONAL SUPPLY RESOURCES OR REDUCTION IN DEMAND IS ASSUMED TO BE 50% OF THE CALCULATED PRICE CHANGE. THE ESTIMATED CAPACITY MARKET PRICE EFFECT IS THEN APPLIED TO THE PJM ESTABLISHED LOAD OBLIGATION IN EACH MARYLAND SERVICE TERRITORY TO DETERMINE THE TOTAL PRICE MITIGATION BENEFIT OF THE DEMAND RESPONSE RESOURCE":

A. PLEASE EXPLAIN HOW THE 50% ASSUMPTION WAS DERIVED.
B. PROVIDE ALL DOCUMENTATION USED IN DEVELOPING THE 50% ASSUMPTION.
C. PLEASE PROVIDE ALL DOCUMENTATION AND THE MODEL THAT WAS USED TO CALCULATE THE ESTIMATED CAPACITY MARKET PRICE EFFECT.
D. PROVIDE ALL ANALYSIS PEPCO USED TO CALCULATE THE PRICE MITIGATION BENEFITS IN EACH OF THE MARYLAND SERVICE TERRITORIES THAT WERE USED TO DETERMINE THE TOTAL PRICE MITIGATION BENEFIT.

RESPONSE:

A. The 50% slope assumption was an outcome of the MEA lead Energy Planning Group (EPG) and was an assumption that in the absence of certainty about the slope of the supply curve, that an assumed 45 degree slope would be a conservative estimate. Previously a vertical supply curve had been assumed.

B. On August 19 2014, MEA filed findings of the EPG the working group with the Maryland PSC. The 50% solution was adopted by the group. See OPC DR 8-20 Attachment.

C. Please refer to Staff DR 6-1, Attachment L. The working papers submitted detail the VRR B-C 50% Capacity DRIPE impact for a 1 MW reduction.

D. Please refer to the response to part (c).

SPONSOR: Mario Giovannini

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MD 9418 OPC DR 8-20 Attachment

RTO	2014-15	2015-16	2016-17	2017-18	Notes
Forecast Pool Requirement (FPR)	1.0809	1.0859	1.0902	1.0916	
Demand Resource (DR) Factor	0.956	0.955	0.955	0.953	

RTO - PE	2014-15	2015-16	2016-17	2017-18	
Point (a) UCAP Price, $/MW-Day	$513.35	$480.95	$495.80	$527.09	
Point (b) UCAP Price, $/MW-Day	$342.23	$320.63	$330.53	$351.39	
Point (c) UCAP Price, $/MW-Day	$68.45	$64.13	$66.11	$70.28	
Point (a) UCAP Level, MW	140,755.8	154,476.4	157,663.0	156,603.4	
Point (b) UCAP Level, MW	145,901.4	160,118.5	163,411.4	162,308.1	
Point (c) UCAP Level, MW	151,047.1	165,760.7	169,159.7	168,012.7	
VRR A-B Slope ($/MW-Day/MW)	-$0.0333	-$0.0284	-$0.0288	-$0.0308	
VRR B-C Slope ($/MW-Day/MW)	-$0.0532	-$0.0455	-$0.0460	-$0.0493	
Supply Slope	$0.0179	$0.0179	$0.0082	$0.0082	From PJM Supply Curve figures
DRIPE from 1 MW shift of VRR Curve	$0.0163	$0.0129	$0.0070	$0.0070	2016/17 supply curve used for 2017/18

RTO - PE	2014-15	2015-16	2016-17	2017-18	
PE Summer Peak	1,481.0	1,507.0	1,531.0	1,544.0	Maryland Summer Net Peak from PSC Ten Year Plan
PE UCAP Obligation	1,600.8	1,636.5	1,669.1	1,685.4	
Capacity DRIPE ($/MW-Day/MW) - Along VRR	**$85.17**	**$74.39**	**$76.78**	**$83.05**	**DRIPE when moving along VRR curve (vertical demand curve assumption)**
Capacity DRIPE ($/MW-Day/MW) - 50% Solution	**$42.59**	**$37.20**	**$38.39**	**$41.53**	**DRIPE with diagonal supply curve assumption**
Capacity DRIPE ($/MW-Day/MW) - Along Supply	**$28.70**	**$29.34**	**$13.75**	**$13.89**	**DRIPE when moving along the supply curve**
Capacity DRIPE ($/MW-Day/MW) - New Equilibrium	**$26.04**	**$21.04**	**$11.66**	**$11.78**	**DRIPE at new equilibrium with VRR curve shift**

MAAC - All others	2014-15	2015-16	2016-17	2017-18	
Point (a) UCAP Price, $/MW-Day	$362.87	$401.42	$415.35	$469.50	
Point (b) UCAP Price, $/MW-Day	$241.91	$267.61	$276.90	$313.00	
Point (c) UCAP Price, $/MW-Day	$48.38	$53.52	$55.38	$62.60	
Point (a) UCAP Level, MW	68,641.5	68,102.2	68,758.0	68,024.0	
Point (b) UCAP Level, MW	71,145.8	70,584.8	71,259.7	70,497.1	
Point (c) UCAP Level, MW	73,650.1	73,067.4	73,761.4	72,970.2	
A-B Slope ($/MW-Day/MW)	-$0.0483	-$0.0539	-$0.0553	-$0.0633	
B-C Slope ($/MW-Day/MW)	-$0.0773	-$0.0862	-$0.0885	-$0.1012	
Supply Slope	$0.0600	$0.0384	$0.0207	$0.0207	From PJM Supply Curve figures
DRIPE from 1 MW shift of VRR Curve	$0.0338	$0.0266	$0.0167	$0.0167	2016/17 supply curve used for 2017/18

MAAC - All others	2014-15	2015-16	2016-17	2017-18	
Pepco Summer Peak	3,243.0	3,226.0	3,180.0	3,139.0	Maryland Summer Net Peak from PSC Ten Year Plan
DPL Summer Peak	924.0	879.0	965.0	857.0	Maryland Summer Net Peak from PSC Ten Year Plan
SMECO Summer Peak	857.0	873.0	889.0	905.0	
BGE UCAP Obligation	8,004.1	7,924.9	7,945.4	7,916.3	PJM data
Pepco UCAP Obligation	3,505.4	3,503.1	3,466.8	3,426.5	Summer peak * FPR
DPL UCAP Obligation	998.8	954.5	1,052.0	935.5	Summer peak * FPR
SMECO UCAP Obligation	926.3	948.0	969.2	987.9	Summer peak * FPR
Total MAAC MD Obligation	13,434.5	13,330.5	13,433.4	13,266.2	
Capacity DRIPE ($/MW-Day UCAP) - Along VRR	**$1,038.21**	**$1,149.57**	**$1,189.50**	**$1,343.20**	**DRIPE when moving along VRR curve**
Capacity DRIPE ($/MW-Day/MW) - 50% Solution	**$519.10**	**$574.79**	**$594.75**	**$671.60**	**DRIPE with diagonal supply curve assumption**
Capacity DRIPE ($/MW-Day UCAP) - Along Supply	**$806.65**	**$512.35**	**$277.46**	**$274.00**	**DRIPE when moving along the supply curve**
Capacity DRIPE ($/MW-Day UCAP) - New Equilibrium	**$453.95**	**$354.40**	**$224.98**	**$222.18**	**DRIPE at new equilibrium with VRR curve shift**

Annualized DRIPE ($/MW-Day/MW) - Along VRR	2015	2016	2017	
PE	**$80.68**	**$75.39**	**$79.39**	**Annualized from respective energy years**
BGE	**$1,084.61**	**$1,166.21**	**$1,253.54**	
Pepco	**$1,084.61**	**$1,166.21**	**$1,253.54**	
SMECO	**$1,084.61**	**$1,166.21**	**$1,253.54**	
DPL	**$1,084.61**	**$1,166.21**	**$1,253.54**	

Annualized DRIPE ($/MW-Day/MW) - 50% Solution	2015	2016	2017	
PE	**$40.34**	**$37.69**	**$39.70**	**Per Bill Pino suggestion of 50% vertical/50% horizontal curve. Functionally 1/2 the value of a vertical shift represented by the "Along VRR" method**
BGE	**$542.30**	**$583.10**	**$626.77**	
Pepco	**$542.30**	**$583.10**	**$626.77**	
SMECO	**$542.30**	**$583.10**	**$626.77**	
DPL	**$542.30**	**$583.10**	**$626.77**	

Annualized DRIPE ($/MW-Day/MW) - Along Supply	2015	2016	2017
PE	**$28.97**	**$22.85**	**$13.81**
BGE	**$684.03**	**$414.48**	**$276.02**
Pepco	**$684.03**	**$414.48**	**$276.02**
SMECO	**$684.03**	**$414.48**	**$276.02**
DPL	**$684.03**	**$414.48**	**$276.02**

Annualized DRIPE ($/MW-Day/MW) - New Equilibrium	2015	2016	2017
PE	**$23.96**	**$17.14**	**$11.71**
BGE	**$412.47**	**$300.47**	**$223.81**
Pepco	**$412.47**	**$300.47**	**$223.81**
SMECO	**$412.47**	**$300.47**	**$223.81**
DPL	**$412.47**	**$300.47**	**$223.81**

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SWMAAC - Not used as SWMAAC didn't bind	2014-15	2015-16	2016-17	2017-18	
Point (a) UCAP Price, $/MW-Day	$362.87	$401.42	$415.35	$469.50	
Point (b) UCAP Price, $/MW-Day	$241.91	$267.61	$276.90	$313.00	
Point (c) UCAP Price, $/MW-Day	$48.38	$53.52	$55.38	$62.60	
Point (a) UCAP Level, MW	16,517.2	16,405.7	16,482.7	16,114.3	
Point (b) UCAP Level, MW	17,119.4	17,003.2	17,081.8	16,699.8	
Point (c) UCAP Level, MW	17,721.6	17,600.7	17,681.0	17,285.3	
A-B Slope ($/MW-Day/MW)	-$0.2009	-$0.2239	-$0.2311	-$0.2673	
B-C Slope ($/MW-Day/MW)	-$0.3214	-$0.3583	-$0.3697	-$0.4277	

SWMAAC - Not used as SWMAAC didn't bind	2014-15	2015-16	2016-17	2017-18	
Pepco Summer Peak	3,243.0	3,226.0	3,180.0	3,139.0	Maryland Summer Net Peak from PSC Ten Year Plan
BGE UCAP Obligation	8,004.1	7,924.9	7,945.4	7,916.3	PJM data
Pepco UCAP Obligation	3,100.3	3,080.8	3,036.9	2,991.5	Summer peak * FPR
Total SWMAAC MD Obligation	11,104.4	11,005.7	10,982.3	10,907.8	
Capacity DRIPE ($/MW-Day/MW) - Along VRR	**$3,568.63**	**$3,943.46**	**$4,060.07**	**$4,664.90**	

DPL-South - Not used as DPL South didn't bind	2014-15	2015-16	2016-17	2017-18	
Point (a) UCAP Price, $/MW-Day	$412.53	$470.76	$494.91	$548.81	
Point (b) UCAP Price, $/MW-Day	$275.02	$313.84	$329.94	$365.87	
Point (c) UCAP Price, $/MW-Day	$55.00	$62.77	$65.99	$73.17	
Point (a) UCAP Level, MW	2,875.5	2,916.8	3,011.5	3,065.5	
Point (b) UCAP Level, MW	2,980.2	3,022.9	3,120.9	3,176.7	
Point (c) UCAP Level, MW	3,084.9	3,129.0	3,230.2	3,287.8	
A-B Slope ($/MW-Day/MW)	-$1.3134	-$1.4790	-$1.5080	-$1.6451	
B-C Slope ($/MW-Day/MW)	-$2.1014	-$2.3664	-$2.4149	-$2.6346	

SWMAAC - Not used as SWMAAC didn't bind	2014-15	2015-16	2016-17	2017-18	
DPL Summer Peak	924.0	879.0	965.0	857.0	Maryland Summer Net Peak from PSC Ten Year Plan
DPL UCAP Obligation	998.8	954.5	1,052.0	935.5	Summer peak * FPR
Capacity DRIPE ($/MW-Day/MW) - Along VRR	**$2,098.81**	**$2,258.70**	**$2,540.59**	**$2,464.64**	

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2014-2015 RPM Base Residual Auction Planning Parameters with FRR Adjustments						5/11/2011	626190v9	

See notes below for summary of updates made to parameters originally posted on 2/1/11.

	RTO	Notes:
Installed Reserve Margin (IRM)	15.3%	1. Load data: from 2011 Load Report, adjusted for Non-Zone Load.
Pool-Wide Average EFORd	6.25%	2. See "Net CONE" worksheet for Net CONE calculations.
Forecast Pool Requirement (FPR)	1.0809	3. New Fixed Resource Requirement (FRR) elections were made in DEOK Zone on 3/2/11.
Demand Resource (DR) Factor	0.956	4. Reliability Requirement and Short-Term Resource Procurement Target are reduced due to FRR elections.
Preliminary Forecast Peak Load	164,757.6	
Short-Term Resource Procurement Target	2.5%	
Pre-Clearing BRA Credit Rate, $/MW	$37,474	

		LOCATIONAL DELIVERABILITY AREA (LDA)						
	RTO	MAAC	EMAAC	SWMAAC	PS	PS NORTH	DPL SOUTH	PEPCO
CETO	NA	2,020.0	5,790.0	5,420.0	4,880.0	2,110.0	1,410.0	3,500.0
CETL	NA	5,694.0	8,189.0	7,718.5	5,720.7	2,372.0	1,925.0	5,606.3
Reliability Requirement	178,086.5	72,187.0	39,995.0	17,358.0	13,099.0	6,211.0	3,018.0	8,951.0
Total Peak Load of FRR Entities	27,535.8	0	0	0	0	0	0	0
Preliminary FRR Obligation	**29,763.4**	0	0	0	0	0	0	0
Reliability Requirement adjusted for FRR	**148,323.1**	**72,187.0**	**39,995.0**	**17,358.0**	**13,099.0**	**6,211.0**	**3,018.0**	**8,951.0**
Short-Term Resource Procurement Target	3,708.1	1,667.3	910.1	389.2	294.6	134.0	64.0	189.1
Net CONE, $/MW-Day (UCAP Price)	**$342.23**	**$241.91**	**$275.02**	**$241.91**	**$275.02**	**$275.02**	**$275.02**	**$241.91**
Variable Resource Requirement Curve:								
Point (a) UCAP Price, $/MW-Day	$513.35	$362.87	$412.53	$362.87	$412.53	$412.53	$412.53	$362.87
Point (b) UCAP Price, $/MW-Day	$342.23	$241.91	$275.02	$241.91	$275.02	$275.02	$275.02	$241.91
Point (c) UCAP Price, $/MW-Day	$68.45	$48.38	$55.00	$48.38	$55.00	$55.00	$55.00	$48.38
Point (a) UCAP Level, MW	140,755.8	68,641.5	38,044.3	16,517.2	12,463.6	5,915.4	2,875.5	8,529.1
Point (b) UCAP Level, MW	145,901.4	71,145.8	39,431.8	17,119.4	12,918.0	6,130.8	2,980.2	8,839.6
Point (c) UCAP Level, MW	151,047.1	73,650.1	40,819.3	17,721.6	13,372.5	6,346.3	3,084.9	9,150.1
Participant-Funded ICTRs Awarded	NA	159.0	NA	NA	NA	NA	NA	NA
Post-Clearing BRA Credit Rate (LMT), $/MW	$ 9,159.31	$ 9,159.31	$ 9,159.31	$ 9,159.31	$ 9,159.31	$ 15,619.81	$ 9,159.31	$ 9,159.31
Post-Clearing BRA Credit Rate (ES), $/MW	$ 9,197.27	$ 9,964.50	$ 9,964.50	$ 9,964.50	$ 9,964.50	$ 16,425.00	$ 9,964.50	$ 9,964.50
Post-Clearing BRA Credit Rate (ANL), $/MW	$ 9,197.27	$ 9,964.50	$ 9,964.50	$ 9,964.50	$ 9,964.50	$ 16,425.00	$ 9,964.50	$ 9,964.50
Min Ext Summer Resource Req'ment, MW	137,808.8	61,255.3	28,773.1	8,402.1	6,374.1	3,382.1	887.0	2,729.1
Min Annual Resource Req'ment, MW	128,450.2	57,748.7	25,397.4	7,152.1	4,977.3	2,813.2	654.4	1,897.8
FRR Load Requirements:								
Min % Internal Resource Req'ment	NA	99.7%	87.4%	61.9%	62.6%	71.6%	42.7%	44.2%
Min % Ext Summer Resource Req'ment	95.4%	NA	NA	NA	NA	NA	NA	NA
Min % Annual Resource Req'ment	89.1%	NA	NA	NA	NA	NA	NA	NA

LDA CETO/CETL Data; Zonal Peak Loads, Base Zonal FRR Scaling Factors, and Zonal Short-Term Resource Procurement Target.
*** (Asterisk) – LDA has adequate internal resources to meet the reliability criterion.**
DPL and PS Zonal peak loads and Short-Term Resource Procurement Targets include the corresponding DPL SOUTH and PS NORTH values.

LDA/Zone	CETO	CETL	CETL to CETO Ratio	2010 Zonal W/N	Preliminary Zonal	Base Zonal FRR	Short-Term	FRR Portion of the	Preliminary Zonal
RTO	NA	NA	NA	**152,947.0**	**164,757.6**	NA	**3,708.1**	**27,535.8**	**137,221.8**
AE	1,440	> 1656	> 115%	2,550.0	2,773.0	1.08745	74.9	0.0	2,773.0
AEP	*	*	NA	22,460.0	24,273.0	1.08072	62.2	21,972.8	2,300.2
APS	270	> 311	> 115%	8,280.0	8,639.0	1.04336	233.4	0.0	8,639.0
ATSI	3,670	> 4221	> 115%	12,600.0	13,542.0	1.07476	365.9	0.0	13,542.0
BGE	4,190	> 4819	> 115%	7,080.0	7,405.0	1.04590	200.1	0.0	7,405.0
COMED	1,980	> 2277	> 115%	21,580.0	23,649.0	1.09588	639.1	0.0	23,649.0
DAYTON	730	> 840	> 115%	3,340.0	3,564.0	1.06707	96.3	0.0	3,564.0
DEOK (adjusted for Non-Zone Load)	2,630	> 3025	> 115%	5,267.0	5,811.6	1.10340	6.7	5,563.0	248.6
DLCO	1,030	> 1185	> 115%	2,800.0	2,961.0	1.05750	80.0	0.0	2,961.0
DOM	690	> 794	> 115%	18,960.0	20,618.0	1.08745	557.2	0.0	20,618.0
DPL	1,260	> 1449	> 115%	3,900.0	4,121.0	1.05667	111.4	0.0	4,121.0
DPL SOUTH	1,410	**1,925.0**	137%	NA	2,369.2	NA	64.0	0.0	2,369.2
JCPL	3,890	> 4474	> 115%	6,080.0	6,539.0	1.07549	176.7	0.0	6,539.0
METED	510	> 587	> 115%	2,720.0	3,051.0	1.12169	82.4	0.0	3,051.0
PECO	2,680	> 3082	> 115%	8,270.0	8,911.0	1.07751	240.8	0.0	8,911.0
PENLC	730	> 840	> 115%	2,630.0	2,986.0	1.13536	80.7	0.0	2,986.0
PEPCO	3,500	**5,606.3**	160%	6,730.0	6,996.0	1.03952	189.1	0.0	6,996.0
PL (incl. UGI)	390	> 449	> 115%	6,950.0	7,584.0	1.09122	204.9	0.0	7,584.0
PS	4,880	**5,720.7**	117%	10,340.0	10,901.0	1.05426	294.6	0.0	10,901.0
PS NORTH	2,110	**2,372.0**	112%	NA	4,960.0	NA	134.0	0.0	4,960.0
RECO	NA	NA	NA	410.0	433.0	1.05610	11.7	0.0	433.0
EMAAC	5,790	**8,189.0**	141%	NA	33,678.0	NA	910.1	0.0	** Used to allocate Short-Term Resource Procurement Target to Zones.
SWMAAC	5,420	**7,718.5**	142%	NA	14,401.0	NA	389.2	0.0	
Western MAAC	*	*	NA	NA	13,621.0	NA	368.1	0.0	
MAAC	2,020	**5,694.0**	282%	NA	61,700.0	NA	1,667.3	0.0	
Western PJM	*	*	NA	NA	82,439.6	NA	1,483.6	27,535.8	

Limiting conditions at the CETL for modeled LDAs

LDA	Limiting Facility
MAAC	Meadow Brook 500 kV
EMAAC	Rock Springs - Keeney 500 kV line
SWMAAC	Pleasant View - Edwards Ferry 230 kV line
PS, PSNORTH	Cedar Grove F - Clifton K 230 kV line
DPLSOUTH	Easton - Trappe 69 kV line
PEPCO	Pleasant View - Edwards Ferry 230 kV line

Notes: 4/7/11 Revision: Adjustments made to account for Fixed Resource Requirements (FRR) elections made in DEOK Zone. Added Min Resource Requirements for PS, PS NORTH, DPL SOUTH, and PEPCO. See Min Res Req'ments tab for additional changes.

5/13/2011: Updated with Post-BRA Credit rates for Limited (LMT), Extended Summer (ES), and Annual (ANL) resources

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2015-2016 RPM Base Residual Auction Planning Parameters	5/23/2012	680092-v6

See note below on 5-23-12 update.

	RTO	Notes:
Installed Reserve Margin (IRM)	15.4%	1. Load data: from 2012 Load Report.
Pool-Wide Average EFORd	5.90%	2. See "Net CONE" worksheet for Net CONE calculations.
Forecast Pool Requirement (FPR)	1.0859	3. Fixed Resource Requirement (FRR) load still in 5-year commitment period is included.
Demand Resource (DR) Factor	0.955	4-6-12 update includes (changes in input data are shown in red):
Preliminary Forecast Peak Load	163,168.0	Additional FRR load elected by FRR entities on 3-7-12.
Short-Term Resource Procurement Target	2.5%	Changes in CETO/CETL/Reliability Requirements in LDAs.
Pre-Clearing BRA Credit Rate, $/MW	**$35,205.17**	Changes in Min Annual Resource and Min Extended Resource Requirements.

		LOCATIONAL DELIVERABILITY AREA (LDA)							
	RTO	**MAAC**	**EMAAC**	**SWMAAC**	**PS**	**PS NORTH**	**DPL SOUTH**	**PEPCO**	**ATSI**
CETO	NA	100.0	3,860.0	4,720.0	4,600.0	2,240.0	1,510.0	3,380.0	5,280.0
CETL	NA	6,156.0	9,177.0	8,373.0	6,220.0	2,972.0	1,822.0	6,522.0	5,417.8
Reliability Requirement	177,184.1	71,623.0	39,370.0	17,238.0	12,824.0	6,462.0	3,062.0	8,973.0	16,201.0
Total Peak Load of FRR Entities	13,267.1	0	0	0	0	0	0	0	0
Preliminary FRR Obligation	**14,406.7**	0	0	0	0	0	0	0	0
Reliability Requirement adjusted for FRR	**162,777.4**	**71,623.0**	**39,370.0**	**17,238.0**	**12,824.0**	**6,462.0**	**3,062.0**	**8,973.0**	**16,201.0**
Short-Term Resource Procurement Target	4,069.4	1,658.9	903.5	384.2	288.4	138.3	65.6	186.0	360.5
Net CONE, $/MW-Day (UCAP Price)	**$320.63**	**$267.61**	**$313.84**	**$267.61**	**$313.84**	**$313.84**	**$313.84**	**$267.61**	**$358.22**
Variable Resource Requirement Curve:									
Point (a) UCAP Price, $/MW-Day	$480.95	$401.42	$470.76	$401.42	$470.76	$470.76	$470.76	$401.42	$537.33
Point (b) UCAP Price, $/MW-Day	$320.63	$267.61	$313.84	$267.61	$313.84	$313.84	$313.84	$267.61	$358.22
Point (c) UCAP Price, $/MW-Day	$64.13	$53.52	$62.77	$53.52	$62.77	$62.77	$62.77	$53.52	$71.64
Point (a) UCAP Level, MW	154,476.4	68,102.2	37,443.0	16,405.7	12,202.2	6,155.7	2,916.8	8,553.7	15,419.3
Point (b) UCAP Level, MW	160,118.5	70,584.8	38,807.6	17,003.2	12,646.7	6,379.7	3,022.9	8,864.7	15,980.8
Point (c) UCAP Level, MW	165,760.7	73,067.4	40,172.3	17,600.7	13,091.2	6,603.7	3,129.0	9,175.7	16,542.4
Participant-Funded ICTRs Awarded	NA	159.0	NA	NA	NA	NA	NA	NA	NA
Post-Clearing BRA Credit Rate (LMT), $/MW	$8,677.13	$10,980.00	$10,980.00	$10,980.00	$10,980.00	$10,980.00	$10,980.00	$10,980.00	$22,298.18
Post-Clearing BRA Credit Rate (ES), $/MW	$9,955.20	$12,258.07	$12,258.07	$12,258.07	$12,258.07	$12,258.07	$12,258.07	$12,258.07	$23,576.26
Post-Clearing BRA Credit Rate (ANL), $/MW	$9,955.20	$12,258.07	$12,258.07	$12,258.07	$12,258.07	$12,258.07	$12,258.07	$12,258.07	$26,132.40
Min Ext Summer Resource Req'ment, MW	155,315.7	61,854.9	28,122.1	7,969.8	5,887.9	3,146.6	1,099.6	2,031.7	10,039.5
Min Annual Resource Req'ment, MW	146,454.9	58,496.3	24,394.6	6,693.1	4,808.2	2,586.6	894.0	1,186.0	9,226.9
FRR Load Requirements:									
Min % Internal Resource Req'ment	NA	98.7%	83.5%	57.7%	57.2%	63.1%	47.2%	32.9%	74.8%
Min % Ext Summer Resource Req'ment	95.0%	86.4%	71.4%	46.2%	45.9%	48.7%	35.9%	22.6%	62.0%
Min % Annual Resource Req'ment	89.1%	81.7%	62.0%	38.8%	37.5%	40.0%	29.2%	13.2%	57.0%

LDA CETO/CETL Data; Zonal Peak Loads, Base Zonal FRR Scaling Factors, and Zonal Short-Term Resource Procurement Target.

*** (Asterisk) – LDA has adequate internal resources to meet the reliability criterion.**

DPL and PS Zonal peak loads and Short-Term Resource Procurement Targets include the corresponding DPL SOUTH and PS NORTH values.

LDA/Zone	CETO	CETL	CETL to CETO Ratio	2011 Zonal W/N	Preliminary Zonal	Base Zonal FRR	Short-Term	FRR Portion of the	Preliminary Zonal
RTO	NA	NA	NA	**151,995.0**	**163,168.0**	NA	**4,069.4**	**13,267.1**	**149,900.9**
AE	760.0	> 874.0	> 115%	2,520.0	2,735.0	1.08532	74.2	0.0	2,735.0
AEP	580	> 667.0	> 115%	22,460.0	23,991.0	1.06817	315.6	12,364.7	11,626.3
APS	840.0	> 966.0	> 115%	8,210.0	8,753.0	1.06614	237.6	0.0	8,753.0
ATSI	5,280.0	5,417.8	103%	12,620.0	13,281.0	1.05238	360.5	0.0	13,281.0
BGE	3,630.0	> 4174.5	> 115%	6,960.0	7,298.0	1.04856	198.1	0.0	7,298.0
COMED	1,740.0	> 2001.0	> 115%	21,480.0	23,563.0	1.09697	639.7	0.0	23,563.0
DAYTON	440.0	> 506.0	> 115%	3,180.0	3,498.0	1.10000	95.0	0.0	3,498.0
DEOK	2,840.0	> 3266.0	> 115%	5,250.0	5,665.0	1.07905	129.3	902.4	4,762.6
DLCO	1,370.0	> 1575.5	> 115%	2,800.0	2,969.0	1.06036	80.6	0.0	2,969.0
DOM	*	*	NA	18,530.0	20,341.0	1.09773	552.2	0.0	20,341.0
DPL	1,230.0	> 1414.5	> 115%	3,920.0	4,175.0	1.06505	113.3	0.0	4,175.0
DPL SOUTH	1,510.0	1,822.0	121%	NA	2,417.7	NA	65.6	0.0	2,417.7
JCPL	3,530.0	> 4059.5	> 115%	5,960.0	6,349.0	1.06527	172.4	0.0	6,349.0
METED	1,070.0	> 1230.5	> 115%	2,800.0	3,061.0	1.09321	83.1	0.0	3,061.0
PECO	2,490.0	> 2863.5	> 115%	8,370.0	8,977.0	1.07252	243.7	0.0	8,977.0
PENLC	880.0	> 1012.0	> 115%	2,720.0	3,029.0	1.11360	82.2	0.0	3,029.0
PEPCO	3,380.0	6,522.0	193%	6,600.0	6,853.0	1.03833	186.0	0.0	6,853.0
PL (incl. UGI)	500.0	> 575.0	> 115%	7,065.0	7,584.0	1.07346	205.9	0.0	7,584.0
PS	4,600.0	6,220.0	135%	10,150.0	10,624.0	1.04670	288.4	0.0	10,624.0
PS NORTH	2,240.0	2,972.0	133%	NA	5,094.2	NA	138.3	0.0	5,094.2
RECO	NA	NA	NA	400.0	422.0	1.05500	11.5	0.0	422.0
EMAAC	3,860.0	9,177.0	238%	NA	33,282.0	NA	903.5	0.0	** Used to allocate Short-Term Resource Procurement Target to Zones.
SWMAAC	4,720.0	8,373.0	177%	NA	14,151.0	NA	384.2	0.0	
Western MAAC	*	*	NA	NA	13,674.0	NA	371.2	0.0	
MAAC	100.0	6,156.0	6156%	NA	61,107.0	NA	1,658.9	0.0	
Western PJM	4,440	> 5106.0	> 115%	NA	81,720.0	NA	1,858.3	13,267.1	

Limiting conditions at the CETL for modeled LDAs:

LDA	Limiting Facility
MAAC	Loudoun - Brambleton 500 kV line.
EMAAC	Peach Bottom - Limerick 500 kV line.
SWMAAC	Voltage drop at Brighton 500 kV.
PS	Cedar Grove F - Clifton K 230 kV line.
PSNORTH	Cedar Grove F - Clifton K 230 kV line.
DPLSOUTH	Wye Mill - Long Wood 69 kV line.
PEPCO	Voltage drop at Brighton 500 kV.
ATSI	South Canton 765/345 kV transformer.

4-17-12 Update: SWMAAC and PEPCO CETL values and limiting facility were updated based on corrected rating on Pleasant View - Edwards Ferry 230 kV line.

5-23-12 Update: Added Post-Clearing BRA Credit Rates.

2016-2017 RPM Base Residual Auction Planning Parameters | **4/30/2013** | **734653-v6**

Updated on 4/30/2013

	RTO	Notes:
Installed Reserve Margin (IRM)	15.6%	1. Load data: from 2013 Load Report.
Pool-Wide Average EFORd	5.69%	2. Adjustments were made in the Zonal Peak Load Forecast of AEP, DEOK, and EKPC to account for EKPC integration.
Forecast Pool Requirement (FPR)	1.0902	3. See "Net CONE" worksheet for Net CONE calculations.
Demand Resource (DR) Factor	0.955	Planning Parameters were updated on 4/16/2013 to reflect: (1) FRR Elections for which FRR Obligations were satisfied by the 4/13/2013 deadline; (2) increased CETL for
Preliminary Forecast Peak Load	165,412.0	SWMAAC, PEPCO and DPL SOUTH LDAs associated with customer-funded upgrades for which ICTR certifications were made by the 3/29/2013 deadline; and (3) 13 MW
Short-Term Resource Procurement Target	2.5%	decrease in EKPC forecast load due to correction of historical load data used in original EKPC load forecast.
Pre-Clearing BRA Credit Rate, $/MW	**$36,193.04**	Limited DR Reliability Targets revised based on FERC approved alternate methodology (Filing 20121130-er13-486-000).

		LOCATIONAL DELIVERABILITY AREA (LDA)								
	RTO	**MAAC**	**EMAAC**	**SWMAAC**	**PS**	**PS NORTH**	**DPL SOUTH**	**PEPCO**	**ATSI**	**ATSI-Cleveland**
CETO	NA	5,220.0	6,140.0	5,840.0	6,450.0	2,450.0	1,580.0	2,730.0	5,390.0	3,800.0
CETL	NA	6,495.0	8,916.0	8,786.0	6,581.0	2,936.0	1,901.0	6,846.0	7,881.0	5,245.0
Reliability Requirement	180,332.2	72,299.0	39,694.0	17,316.0	12,870.0	6,440.0	3,160.0	9,012.0	16,255.0	6,164.0
Total Peak Load of FRR Entities	13,029.4	0	0	0	0	0	0	0	0	0
Preliminary FRR Obligation	14,204.7	0	0	0	0	0	0	0	0	0
Reliability Requirement adjusted for FRR	**166,127.5**	**72,299.0**	**39,694.0**	**17,316.0**	**12,870.0**	**6,440.0**	**3,160.0**	**9,012.0**	**16,255.0**	**6,164.0**
Short-Term Resource Procurement Target	4,153.2	1,664.7	907.6	384.0	288.9	140.1	66.5	185.3	362.4	124.3
Net CONE, $/MW-Day (UCAP Price)	**$330.53**	**$276.90**	**$329.94**	**$276.90**	**$329.94**	**$329.94**	**$329.94**	**$276.90**	**$362.64**	**$362.64**
Variable Resource Requirement Curve:										
Point (a) UCAP Price, $/MW-Day	$495.80	$415.35	$494.91	$415.35	$494.91	$494.91	$494.91	$415.35	$543.96	$543.96
Point (b) UCAP Price, $/MW-Day	$330.53	$276.90	$329.94	$276.90	$329.94	$329.94	$329.94	$276.90	$362.64	$362.64
Point (c) UCAP Price, $/MW-Day	$66.11	$55.38	$65.99	$55.38	$65.99	$65.99	$65.99	$55.38	$72.53	$72.53
Point (a) UCAP Level, MW	157,663.0	68,758.0	37,756.3	16,482.7	12,247.1	6,132.8	3,011.5	8,592.8	15,470.8	5,879.7
Point (b) UCAP Level, MW	163,411.4	71,259.7	39,129.8	17,081.8	12,692.4	6,355.6	3,120.9	8,904.6	16,033.3	6,093.0
Point (c) UCAP Level, MW	169,159.7	73,761.4	40,503.3	17,681.0	13,137.8	6,578.4	3,230.2	9,216.5	16,595.7	6,306.3
Customer-Funded ICTRs Awarded	NA	159.0	NA	444.0	NA	NA	37.0	191.0	NA	NA
Post-Clearing BRA Credit Rate (LMT), $/MW										
Post-Clearing BRA Credit Rate (ES), $/MW										
Post-Clearing BRA Credit Rate (ANL), $/MW										
Min Ext Summer Resource Req'ment, MW	158,512.2	62,179.2	28,559.2	7,503.3	5,483.4	3,113.3	1,114.3	1,712.9	7,668.1	676.8
Min Annual Resource Req'ment, MW	149,469.1	58,109.3	24,606.9	6,183.2	4,214.2	2,503.1	903.5	750.0	6,200.8	0.0
FRR Load Requirements:										
Min % Internal Resource Req'ment	NA	98.8%	84.8%	55.5%	54.4%	62.5%	47.4%	29.2%	57.8%	18.5%
Min % Ext Summer Resource Req'ment	95.0%	86.0%	71.9%	43.3%	42.6%	48.3%	35.3%	19.0%	47.2%	11.0%
Min % Annual Resource Req'ment	89.1%	80.4%	62.0%	35.7%	32.7%	38.9%	28.6%	8.3%	38.1%	0.0%

LDA CETO/CETL Data; Zonal Peak Loads, Base Zonal FRR Scaling Factors, and Zonal Short-Term Resource Procurement Target.

*** (Asterisk) – LDA has adequate internal resources to meet the reliability criterion.**

ATSI, DPL and PS Zonal peak loads and Short-Term Resource Procurement Targets include the corresponding sub-zonal values.

LDA/Zone	**CETO**	**CETL**	**CETL to CETO Ratio**	**2012 Zonal W/N**	**Preliminary Zonal**	**Base Zonal FRR**	**Short-Term**	**FRR Portion of the**	**Preliminary Zonal**
RTO	NA	NA	NA	**154,501.8**	**165,412.0**	NA	**4,153.2**	**13,029.4**	**152,382.6**
AE	1,030	> 1185	> 115%	2,600.0	2,782.0	1.07000	75.8	0	2,782.0
AEP	2,110	> 2427	> 115%	22,663.9	24,007.6	1.05929	324.5	12,102.3	11,905.3
APS	1,970	> 2266	> 115%	8,210.0	8,786.0	1.07016	239.5	0	8,786.0
ATSI	5,390	7,881	146%	12,660.0	13,295.0	1.05016	362.4	0	13,295.0
ATSI-CLEVELAND	3,800	5,245	138%	NA	4,562.3	NA	124.3	0	4,562.3
BGE	5,130	> 5900	> 115%	6,870.0	7,288.0	1.06084	198.6	0	7,288.0
COMED	1,330	> 1530	> 115%	21,650.0	23,504.0	1.08564	640.6	0	23,504.0
DAYTON	960	> 1104	> 115%	3,230.0	3,556.0	1.10093	96.9	0	3,556.0
DEOK	3,800	> 4370	> 115%	5,246.5	5,572.2	1.06208	127.5	894.4	4,677.8
DLCO	1,350	> 1553	> 115%	2,800.0	2,996.0	1.07000	81.7	0	2,996.0
DOM	-70	*	*	18,570.0	20,415.0	1.09935	556.4	0	20,415.0
DPL	1,000	> 1150	> 115%	3,950.0	4,212.0	1.06633	114.8	0	4,212.0
DPL SOUTH	1,580	1,901	120%	NA	2,438.7	NA	66.5	0	2,438.7
EKPC	580	> 667	> 115%	2,096.4	2,200.2	1.04951	59.1	32.7	2,167.5
JCPL	3,300	> 3795	> 115%	5,960.0	6,381.0	1.07064	173.9	0	6,381.0
METED	1,170	> 1346	> 115%	2,820.0	3,068.0	1.08794	83.6	0	3,068.0
PECO	2,860	> 3289	> 115%	8,320.0	8,908.0	1.07067	242.8	0	8,908.0
PENLC	1,300	> 1495	> 115%	2,740.0	3,044.0	1.11095	83.0	0	3,044.0
PEPCO	2,730	6,846	251%	6,540.0	6,800.0	1.03976	185.3	0	6,800.0
PL (incl. UGI)	1,360	> 1564	> 115%	7,075.0	7,581.0	1.07152	206.6	0	7,581.0
PS	6,450	6,581	102%	10,100.0	10,600.0	1.04950	288.9	0	10,600.0
PS NORTH	2,450	2,936	120%	NA	5,141.0	NA	140.1	0	5,141.0
RECO	NA	NA	NA	400.0	416.0	1.04000	11.3	0	416.0
EMAAC	6,140	8,916	145%	NA	33,299.0	NA	907.6	0	** Used to allocate Short-Term Resource Procurement Target to Zones.
SWMAAC	5,840	8,786	150%	NA	14,088.0	NA	384.0	0	
Western MAAC	-3,840	*	*	NA	13,693.0	NA	373.2	0	
MAAC	5,220	6,495	124%	NA	61,080.0	NA	1,664.7	0	
Western PJM	5,940	> 6831	> 115%	NA	83,917.0	NA	1,932.0	13,029.4	

Limiting conditions at the CETL for modeled LDAs:

LDA	**Violation/Limiting Facility**
MAAC	Thermal/Sandy Springs-High Ridge 230 kV
EMAAC	Voltage/Loss of Keeney - Rock Springs 500 kV
SWMAAC	Thermal/Graceton - Bagley 230 kV
PS	Thermal/Roseland - Cedar Grove 230 kV F
PSNORTH	Thermal/Cedar Grove F - Clifton K 230 kV line
DPLSOUTH	Thermal/Easton - Trappe Tap 69 kV
PEPCO	Thermal/Conastone - Northwest 230 kV
ATSI	Thermal/Ashtabula 345/138 kV transformer
ATSI-CLEVELAND	Thermal/Ashtabula 345/138 kV transformer

PLC-2

2017-2018 RPM Base Residual Auction Planning Parameters		3/21/2014	777383-v3A
Updated on 3/21/14 to reflect a revised BGE zone peak load forecast and FRR elections made by the 3/12/14 election deadline.			
	RTO		
Installed Reserve Margin (IRM)	15.7%		
Pool-Wide Average EFORd	5.65%		
Forecast Pool Requirement (FPR)	1.0916		
Demand Resource (DR) Factor	0.953		
Preliminary Forecast Peak Load	164,478.8		
Short-Term Resource Procurement Target	2.5%	**BRA Credit Rate increases to $96,193.01/MW if PJM Tariff changes filed on 3/10/2014**	
Pre-Clearing BRA Credit Rate, $/MW	**$38,477.21**	**in Docket No. ER14-1461-000 are approved.**	

		LOCATIONAL DELIVERABILITY AREA (LDA)											
	RTO	**MAAC**	**EMAAC**	**SWMAAC**	**PS**	**PS NORTH**	**DPL SOUTH**	**PEPCO**	**ATSI**	**ATSI-Cleveland**	**COMED**	**BGE**	**PL**
CETO	NA	4,420.0	6,140.0	5,880.0	6,080.0	2,370.0	1,440.0	3,740.0	4,970.0	3,350.0	2,290.0	4,350.0	1,310.0
CETL	NA	7,393.0	9,315.0	8,053.0	6,700.0	2,795.0	1,869.0	5,359.0	8,470.0	4,940.0	7,020.0	6,217.0	4,336.0
Reliability Requirement	179,545.1	71,534.0	39,371.0	16,935.0	12,759.0	6,465.0	3,215.0	8,715.0	16,009.0	6,250.0	28,991.0	8,701.0	10,813.0
Total Peak Load of FRR Entities	13,318.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	378.5	0.0	0.0
Preliminary FRR Obligation	14,538.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	413.2	0.0	0.0
Reliability Requirement adjusted for FRR	**165,007.1**	**71,534.0**	**39,371.0**	**16,935.0**	**12,759.0**	**6,465.0**	**3,215.0**	**8,715.0**	**16,009.0**	**6,250.0**	**28,577.8**	**8,701.0**	**10,813.0**
Short-Term Resource Procurement Target	4,125.2	1,655.2	902.4	381.5	285.7	138.6	66.1	183.6	357.0	122.5	629.5	197.9	205.1
Net CONE, $/MW-Day (UCAP Price)	**$351.39**	**$313.00**	**$365.87**	**$313.00**	**$365.87**	**$365.87**	**$365.87**	**$313.00**	**$373.75**	**$373.75**	**$373.75**	**$313.00**	**$354.46**
Variable Resource Requirement Curve:													
Point (a) UCAP Price, $/MW-Day	$527.09	$469.50	$548.81	$469.50	$548.81	$548.81	$548.81	$469.50	$560.63	$560.63	$560.63	$469.50	$531.69
Point (b) UCAP Price, $/MW-Day	$351.39	$313.00	$365.87	$313.00	$365.87	$365.87	$365.87	$313.00	$373.75	$373.75	$373.75	$313.00	$354.46
Point (c) UCAP Price, $/MW-Day	$70.28	$62.60	$73.17	$62.60	$73.17	$73.17	$73.17	$62.60	$74.75	$74.75	$74.75	$62.60	$70.89
Point (a) UCAP Level, MW	156,603.4	68,024.0	37,447.7	16,114.3	12,142.4	6,158.8	3,065.5	8,305.4	15,236.9	5,965.4	27,207.3	8,277.5	10,327.5
Point (b) UCAP Level, MW	162,308.1	70,497.1	38,808.9	16,699.8	12,583.5	6,382.3	3,176.7	8,606.7	15,790.3	6,181.5	28,195.3	8,578.3	10,701.3
Point (c) UCAP Level, MW	168,012.7	72,970.2	40,170.0	17,285.3	13,024.7	6,605.8	3,287.8	8,908.0	16,343.8	6,397.6	29,183.3	8,879.1	11,075.1
Participant-Funded ICTRs Awarded	NA	159.0	NA	444.0	NA	NA	37.0	191.0	NA	NA	NA	NA	NA
Post-Clearing BRA Credit Rate (LMT), $/MW													
Post-Clearing BRA Credit Rate (ES), $/MW													
Post-Clearing BRA Credit Rate (ANL), $/MW													
FRR Load Requirement (% Obligation):													
Minimum Internal Resource Requirement	NA	88.8%	74.2%	47.2%	41.4%	49.6%	29.3%	27.0%	40.7%	0.0%	72.6%	21.5%	47.2%

LDA CETO/CETL Data; Zonal Peak Loads, Base Zonal FRR Scaling Factors, and Zonal Short-Term Resource Procurement Targets.

LDA/Zone	CETO	CETL	CETL to CETO Ratio	2013 Zonal W/N	Preliminary Zonal	Base Zonal FRR	Short-Term	FRR Portion of the	Preliminary Zonal
RTO	NA	NA	NA	**155,456.6**	**164,478.8**	NA	**4,125.2**	**13,318.1**	**151,160.7**
AE	1,130.0	> 1300.0	> 115%	2,590.0	2,750.0	1.06178	75.0	0.0	2,750.0
AEP	1,260.0	> 1449	> 115%	22,670.0	23,323.0	1.02880	308.5	12,017.6	11,305.4
APS	3,740.0	> 4301	> 115%	8,270.0	8,841.0	1.06904	241.3	0.0	8,841.0
ATSI	4,970.0	**8,470.0**	170%	12,680.0	13,083.0	1.03178	357.0	0.0	13,083.0
ATSI-CLEVELAND	3,350.0	**4,940.0**	147%	NA	4,489.6	NA	122.5	0.0	4,489.6
BGE	4,350.0	**6,217.0**	143%	6,920.0	7,252.0	1.04798	197.9	0.0	7,252.0
COMED	2,290.0	**7,020.0**	307%	21,830.0	23,447.0	1.07407	629.5	378.5	23,068.5
DAYTON	970.0	> 1116	> 115%	3,260.0	3,503.0	1.07454	95.6	0.0	3,503.0
DEOK	3,760.0	> 4324	> 115%	5,270.0	5,533.0	1.04991	126.4	902.9	4,630.1
DLCO	1,520.0	> 1748	> 115%	2,820.0	2,976.0	1.05532	81.2	0.0	2,976.0
DOM	-540.0	*	*	18,980.0	20,978.0	1.10527	572.5	0.0	20,978.0
DPL	980.0	> 1127	> 115%	3,970.0	4,184.0	1.05390	114.2	0.0	4,184.0
DPL SOUTH	1,440.0	**1,869.0**	130%	NA	2,422.5	NA	66.1	0.0	2,422.5
EKPC	250.0	> 288	> 115%	2,051.6	2,143.8	1.04494	58.0	19.1	2,124.7
JCPL	3,370.0	> 3876	> 115%	6,020.0	6,369.0	1.05797	173.8	0.0	6,369.0
METED	1,290.0	> 1484.0	> 115%	2,840.0	3,061.0	1.07782	83.5	0.0	3,061.0
PECO	3,260.0	> 3749	> 115%	8,360.0	8,881.0	1.06232	242.4	0.0	8,881.0
PENLC	600.0	> 690	> 115%	2,770.0	3,025.0	1.09206	82.6	0.0	3,025.0
PEPCO	3,740.0	**5,359.0**	143%	6,520.0	6,729.0	1.03206	183.6	0.0	6,729.0
PL (incl. UGI)	1,310.0	**4,336.0**	331%	7,115.0	7,517.0	1.05650	205.1	0.0	7,517.0
PS	6,080.0	**6,700.0**	110%	10,120.0	10,470.0	1.03458	285.7	0.0	10,470.0
PS NORTH	2,370.0	**2,795.0**	118%	NA	5,078.0	NA	138.6	0.0	5,078.0
RECO	NA	NA	NA	400.0	413.0	1.03250	11.3	0.0	413.0
EMAAC	6,140.0	**9,315.0**	152%	NA	33,067.0	NA	902.4	0.0	** Used to allocate Short-Term Resource Procurement Target to Zones.
SWMAAC	5,880.0	**8,053.0**	137%	NA	13,981.0	NA	381.5	0.0	
Western MAAC	-5,010.0	*	*	NA	13,603.0	NA	371.2	0.0	
MAAC	4,420.0	**7,393.0**	167%	NA	60,651.0	NA	1,655.2	0.0	
Western PJM	8,210.0	> 9442	> 115%	NA	82,849.8	NA	1,897.5	13,318.1	

*** LDA has adequate internal resources to meet the reliability criterion.**

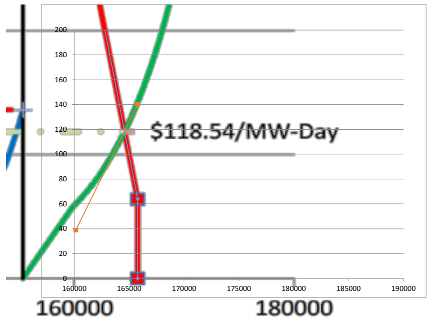
Limiting conditions at the CETL for modeled LDAs:

LDA	Violation/Limiting Facility
MAAC	Thermal / Brister - Ox 500 kV circuit
EMAAC	Voltage / Voltage collapse for the loss of the Keeney - Rock Springs 500 kV circuit.
SWMAAC	Voltage / Voltage collapse for the loss of Burches Hill - Possum Point 500 kV circuit.
PS	Thermal / Roseland - Wilpipe 230 kV circuit.
PSNORTH	Thermal / Roseland - Wilpipe 230 kV circuit.
DPLSOUTH	Thermal/Easton - Trappe Tap 69 kV circuit.
PEPCO	Voltage / Voltage collapse for the loss of Burches Hill - Possum Point 500 kV circuit.
ATSI	Thermal / South Canton - Harmon 345 kV circuit.
ATSI-CLEVELAND	Thermal / South Canton - Harmon 345 kV circuit.
COMED	Thermal / University Park - East Frankfort 345 kV circuit.
BGE	Thermal / Pumphrey 230/115 kV transformer.
PL	Thermal / Wescosville 500/138 kV transformer.

2015/16 RTO

Load	VRR	Supply
0	480.95	
154476.4	480.95	
160118.5	320.63	38.83
165760.7	64.13	140
165760.7	0	

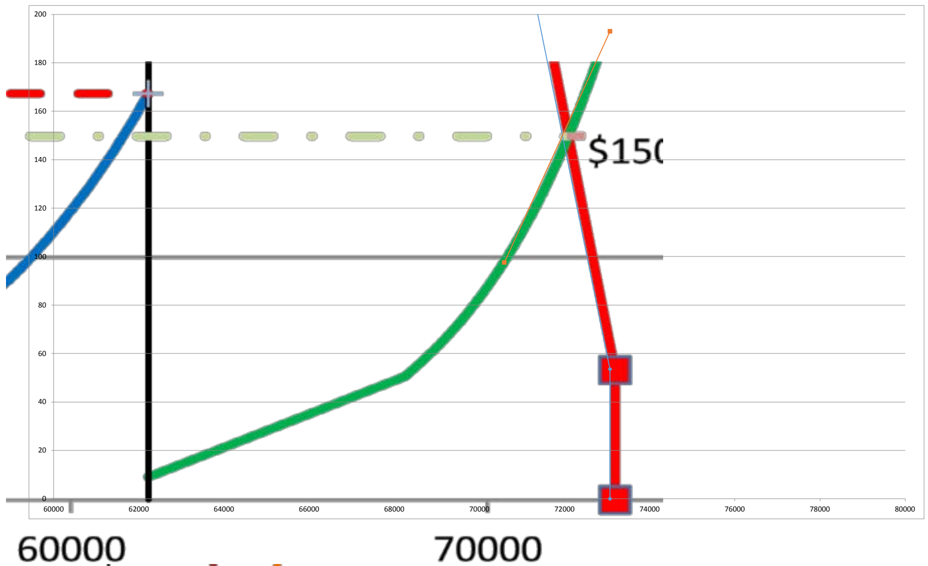
	orig vrr	orig supply
slope	-0.0455	0.0179
b	7599.7756	-2832.1550
x	164563.8497	164563.8497
P	118.5400	118.5400



2015/16 MAAC

Load	VRR	Supply
0	401.42	
68102.2	401.42	
70584.8	267.61	97.58
73067.4	53.52	193
73067.4	0	

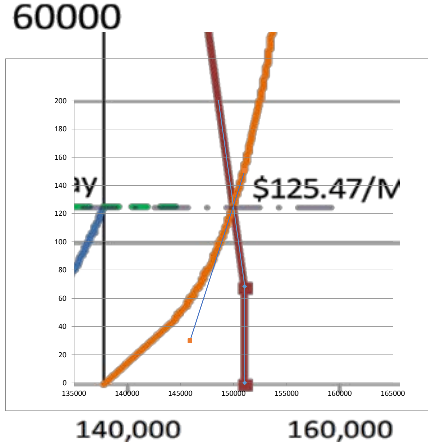
	orig vrr	orig supply
slope	-0.0862	0.0384
b	6354.5752	-2615.3061
x	71948.6123	71948.6123
P	150.0000	150.0000



2014/15 RTO

Load	VRR	Supply
0	513.35	
140755.8	513.35	
145901.4	342.23	30.00
151047.1	68.45	150.5839481
151047.1	0	

	orig vrr	orig supply
slope	-0.0532	0.0234
b	8104.9999	-3389.0425
x	149975.4081	149975.4081
P	125.4700	125.4700



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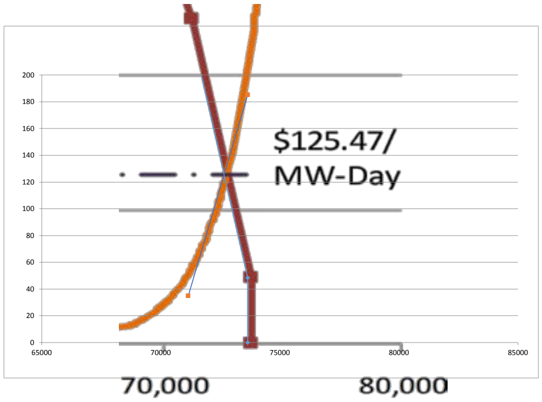
2014/15 MAAC

Load	VRR	Supply
0	362.87	
68641.5	362.87	
71145.8	241.91	35.00
73650.1	48.38	185.3663612
73650.1	0	

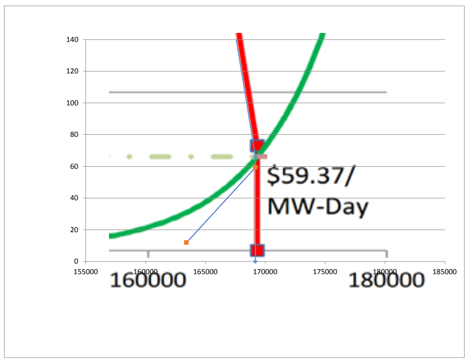
	orig vrr	orig supply
slope	-0.0773	0.0600
b	5739.9920	-4236.8265
x	72652.5467	72652.5467
P	125.4700	125.4700



2016/17 RTO

Load	VRR	Supply
0	495.8	
157663	495.8	
163411.4	330.53	12.00
169159.7	66.11	59.37
169159.7	0	

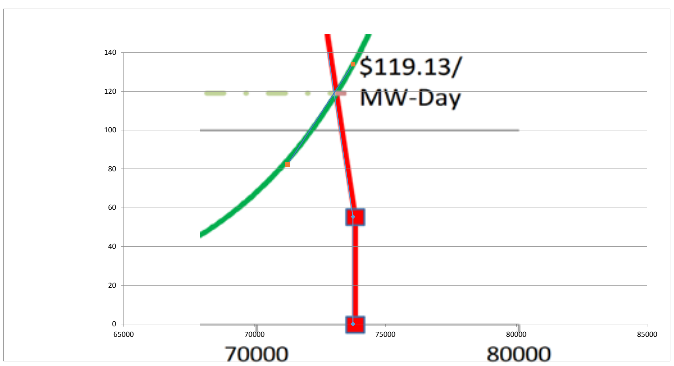
	orig vrr	orig supply
slope	-0.0460	0.0082
b	7847.4032	-1334.6239
x	169306.2227	169306.2227
P	59.3700	60.5774



2016/17 MAAC

Load	VRR	Supply
0	415.35	
68758	415.35	
71259.7	276.9	82.33
73761.4	55.38	134
73761.4	0	

	orig vrr	orig supply
slope	-0.0885	0.0207
b	6586.7888	-1389.4831
x	73041.4498	73041.4498
P	119.1300	119.1300



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2014/15 RTO	VRR	Supply	VRR New
0	513.35		
140755.8	513.35		
145901.4	342.23	30	342.1767944
151047.1	68.45	150.5839481	68.39679441
151047.1	0		

1/b	-0.053205589	0.023433925
a/b	8104.999942	-3389.042473
a	-152333.619	-144621.2047

p	125.47	125.47	-4.09273E-12	solve first
q	149975.4081	149975.4081		

a/b2	8104.946737	-3389.042473		
p2	125.4537314	125.4537314	-5.45697E-12	solve second
q2	149974.7138	149974.7138		

Del P	0.016268576	DRIPE effect
Del D	0.694231816	

2015/16 RTO	VRR	Supply	VRR New
0	480.95		
154476.4	480.95		
160118.5	320.63	38.83311891	320.584539
165760.7	64.13	140	64.08453901
165760.7	0		

1/b	-0.04546099	0.017930396
a/b	7599.77559	-2832.155015
a	-167171.36	-157952.7297

p	118.54	118.54	-3.18323E-12	solve first
q	164563.8497	164563.8497		

a/b2	7599.730129	-2832.155015		
p2	118.5271413	118.5271413	4.54747E-13	solve second
q2	164563.1326	164563.1326		

Del P	0.012858743	DRIPE effect
Del D	0.717147753	

2016/17 RTO	VRR	Supply	VRR New
0	495.8		
157663	495.8		
163411.4	330.53	12	330.4840003
169159.7	66.11	59.37	66.06400031
169159.7	0		

1/b	-0.045999687	0.008240697
a/b	7847.40323	-1334.623875
a	-170596.8837	-161955.2125

p	60.39400269	60.39400269	1.13687E-12	solve first
q	169283.9617	169283.9617		

a/b2	7847.35723	-1334.623875		
p2	60.387014	60.387014	2.27374E-13	solve second
q2	169283.1136	169283.1136		

Del P	0.006988695	DRIPE effect
Del D	0.848070817	

2014/15 MAAC	VRR	Supply	VRR New
0	362.87		
68641.5	362.87		
71145.8	241.91	35	241.8327209
73650.1	48.38	185.3663612	48.30272092
73650.1	0		

1/b	-0.07727908	0.06004327
a/b	5739.991969	-4236.826483
a	-74276.14265	-70562.88704

p	125.47	125.47	-9.09495E-13	solve first
q	72652.54672	72652.54672		

a/b2	5739.91469	-4236.826483		
p2	125.4362102	125.4362102	0	solve second
q2	72651.98396	72651.98396		

Del P	0.033789756	DRIPE effect
Del D	0.562756754	

2015/16 MAAC	VRR	Supply	VRR New
0	401.42		
68102.2	401.42		
70584.8	267.61	97.58260779	267.5237638
73067.4	53.52	193	53.4337638
73067.4	0		

1/b	-0.086236204	0.038434461
a/b	6354.575211	-2615.306116
a	-73688.02101	-68045.86473

p	150	150	1.36424E-12	solve first
q	71948.61235	71948.61235		

a/b2	6354.488974	-2615.306116		
p2	149.9734144	149.9734144	1.81899E-12	solve second
q2	71947.92064	71947.92064		

Del P	0.026585581	DRIPE effect
Del D	0.691712073	

2016/17 MAAC	VRR	Supply	VRR New
0	415.35		
68758	415.35		
71259.7	276.9	82.32937412	276.8114522
73761.4	55.38	134	55.29145221
73761.4	0		

1/b	-0.088547788	0.020654205
a/b	6586.788773	-1389.483113
a	-74386.825	-67273.61716

p	119.13	119.13	-2.27374E-12	solve first
q	73041.44977	73041.44977		

a/b2	6586.700225	-1389.483113		
p2	119.1132523	119.1132523	9.09495E-13	solve second
q2	73040.63891	73040.63891		

Del P	0.016747718	DRIPE effect
Del D	0.810862376	

POTOMAC ELECTRIC POWER COMPANY
MARYLAND CASE NO. 9418
RESPONSE TO OPC DATA REQUEST NO. 8

QUESTION NO. 21

PLEASE REFERENCE THE DIRECT TESTIMONY OF GIOVANNINI, P. 16 AT 12–13:

A. PLEASE PROVIDE ALL REGRESSION MODELING AND DATA USED TO COMPARE HOURLY ENERGY LOAD TO REAL TIME PJM LMPS FOR EACH MARYLAND ZONE BETWEEN JANUARY 1, 2013 AND AUGUST 31, 2015.

B. EXPLAIN WHY REAL-TIME PJM LMPS WERE USED AND NOT DAY-AHEAD.

C. PROVIDE ANY REGRESSION MODELING UTILIZING PJM DAY AHEAD LMPS IN COMPUTER-READABLE FORMAT (EXCEL OR EQUIVALENT).

RESPONSE:

A. Please see the attached files used for the regression modelling and data used. Refer to Staff DR-6-1, Attachment M and see the below attached supporting data files A-H.

The following attachments in question 21 correspond with the following data:
Attachment A: APS-BGE-Hourly LMP (electronic only)
Attachment B: DPL-Pepco- Hourly LMP (electronic only)
Attachment C: APS by SEA TOU w Revised MD Share of Zone
Attachment D: BGE by SEA TOU w Revised MD Share of Zone
Attachment E: DPL by SEA TOU w Revised MD Share of Zone
Attachment F: Pepco by SEA TOU w Revised MD Share of Zone
Attachment G: Zones Combined by SEA TOU w Revised MD Share of Zone
Attachment H: Pepco and DPL Maryland Load corresponding to LMP (electronic only)
Attachment I: BGE and APS Maryland Load corresponding to LMP (electronic only)

B. Real-time PJM LMPs represent the actual prices in the PJM wholesale market given the load and supply conditions. Day-Ahead PJM LMPs provide a forecast of day-ahead electric loads and supply conditions. Pepco relied on actual load and actual energy prices for its analysis.

C. The Company did not perform this modeling.

SPONSOR: Mario Giovannini

POTOMAC ELECTRIC POWER COMPANY
MARYLAND CASE NO. 9418
RESPONSE TO OPC DATA REQUEST NO. 8

QUESTION NO. 22

PLEASE REFERENCE THE DIRECT TESTIMONY OF GIOVANNINI, P. 18 AT 14–16, REFERENCING THE STATEMENT THAT "PEPCO'S AMI-ENABLED DEMAND RESPONSE INITIATIVES HAVE COLLECTIVELY PROVIDED 181 MW OF DEMAND RESPONSE CAPABILITY AND 145 GWH OF ANNUALIZED ENERGY REDUCTIONS FOR THE EMPOWER MARYLAND 2015 YEAR REDUCTIONS GOALS":

A. PLEASE PROVIDE THE ESTIMATED AVOIDED MWS AND GWHS FOR EACH YEAR AND PROGRAM.

B. PLEASE DEFINE THE MEANING OF "181 MW OF DEMAND RESPONSE CAPABILITY." WAS THIS THE ACTUAL REDUCTION IN ONE HOUR, THE ACTUAL REDUCTION IN EVERY HOUR REQUESTED BY PJM, THE AVERAGE REDUCTION IN THE HOURS USED IN THE PJM PEAK-LOAD FORECAST, A POTENTIAL REDUCTION THAT WAS NOT ACTUALLY ACHIEVED, OR SOMETHING ELSE?

RESPONSE:

A. Please refer to Staff DR 6-1, Attachment C, Tabs CVR, Dynamic Pricing, and EMT.

B. The peak demand reduction capability of demand response programs, such as dynamic pricing, is determined based upon the expected demand reduction capability of the program during the typical summer peak load hour at typical weather conditions. The reduction capability for dynamic pricing for EmPOWER reporting purposes is based upon regression modeling estimates. For energy efficiency and energy conservation programs the energy reductions at time of peak represent the demand reduction capability of these programs. Pepco's AMI-enabled EMT and CVR programs provide energy reductions at the time of peak.

SPONSOR: Mario Giovannini

POTOMAC ELECTRIC POWER COMPANY
MARYLAND CASE NO. 9418
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QUESTION NO. 27

PLEASE REFERENCE THE DIRECT TESTIMONY OF GIOVANNINI, P. 20 AT 13–15. PLEASE PROVIDE PJM'S CAPACITY COMPLIANCE METHOD AND ALL CALCULATIONS USED TO DETERMINE THE AVERAGE CAPACITY REDUCTION BENEFITS FROM THE PESC PROGRAM FOR ALL YEARS.

RESPONSE:

Please see the attached.

SPONSOR: Mario Giovannini

2015 PESC Capacity Compliance Results
Pepco MD

21-Jul-15	HE15	HE16	HE17	HE18
Peak Load Contribution (MW)	724	724	724	724
Metered Load (MW)	435	480	522	553
Capacity Loss Factor	1.096	1.096	1.096	1.096
Reduction (MW)	**247**	**198**	**151**	**118**

30-Jul-15	HE15	HE16	HE17	HE18
Peak Load Contribution (MW)	724	724	724	724
Metered Load (MW)	440	438	463	507
Capacity Loss Factor	1.096	1.096	1.096	1.096
Reduction (MW)	**242**	**244**	**217**	**168**

3-Aug-15	HE15	HE16	HE17	HE18
Peak Load Contribution (MW)	724	724	724	724
Metered Load (MW)	478	509	538	563
Capacity Loss Factor	1.096	1.096	1.096	1.096
Reduction (MW)	**200**	**166**	**135**	**107**

9-Sep-15	HE15	HE16	HE17	HE18
Peak Load Contribution (MW)	724	724	724	724
Metered Load (MW)	511	516	525	537
Capacity Loss Factor	1.096	1.096	1.096	1.096
Reduction (MW)	**164**	**158**	**148**	**136**

Average Reduction 175

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POTOMAC ELECTRIC POWER COMPANY
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QUESTION NO. 29

PLEASE REFERENCE THE DIRECT TESTIMONY OF GIOVANNINI, P. 22 AT 11-13 REFERENCING EWR OPERABILITY BENEFITS:

A. PLEASE PROVIDE ALL HOURLY AMI SOURCED DATA PEPCO RELIED ON TO IDENTIFY EWR DEVICE OPERABILITY ISSUES.

B. PLEASE PROVIDE ALL WORKPAPERS AND ANALYSIS IN A WORKABLE FORMAT THAT WERE USED TO IDENTIFY OPERABILITY ISSUES.

RESPONSE:

A. Please refer to Confidential OPC DR 8-29 Attachments A, B and C provided electronically only.

B. Please refer to the response provided to OPC DR 8-2(a) and OPC DR 8-29 Attachment D.

SPONSOR: Mario Giovannini

POTOMAC ELECTRIC POWER COMPANY
MARYLAND CASE NO. 9418
RESPONSE TO STAFF DATA REQUEST NO. 9

QUESTION NO. 4

PAGE 9, LINES 4-8 - FOR THE WHITE FLINT SUBSTATION PROJECT, PLEASE PROVIDE THE DATE THE PROJECT WAS ORIGINALLY CONCEIVED, THE DRIVER FOR THE PROJECT INCLUDING SPECIFIC EQUIPMENT THAT WAS PROJECT TO BE OVERLOADED, THE PERCENT OF THE OVERLOAD, THE NORMAL AND EMERGENCY EQUIPMENT RATINGS, THE PROJECTED LOADING ON THE EQUIPMENT AFTER THE PROJECT IS COMPLETED, THE ORIGINAL PROJECT SERVICE DATE, ALL REVISED PROJECT SERVICE DATE(S) IF THE PROJECT WAS DEFERRED, RATIONALE FOR PROJECT DEFERRALS, AND CURRENT PROJECTED PROJECT COMPLETION DATE.

RESPONSE:

The White Flint Substation Project was originally proposed in 2012 for 2018. Pepco predicted that, without this new substation, the Parklawn Drive Substation would experience a 6% firm capacity overload. Pepco consistently maintained that this substation would be required in 2018 from 2012 to 2015. Recent studies indicate that this substation can be deferred until 2020, based on several factors: delays in customer projects, energy efficiency improvements, and energy reductions caused by the implementation of AMI programs.

SPONSOR: William M. Gausman

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POTOMAC ELECTRIC POWER COMPANY
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RESPONSE TO STAFF DATA REQUEST NO. 9

QUESTION NO. 5

PAGE 9, LINES 4-8 - FOR THE NATIONAL HARBOR SUBSTATION PROJECT, PLEASE PROVIDE THE DATE THE PROJECT WAS ORIGINALLY CONCEIVED, THE DRIVER FOR THE PROJECT INCLUDING SPECIFIC EQUIPMENT THAT WAS PROJECT TO BE OVERLOADED, THE PERCENT OF THE OVERLOAD, THE NORMAL AND EMERGENCY EQUIPMENT RATINGS, THE PROJECTED LOADING ON THE EQUIPMENT AFTER THE PROJECT IS COMPLETED, THE ORIGINAL PROJECT SERVICE DATE, ALL REVISED PROJECT SERVICE DATE(S) IF THE PROJECT WAS DEFERRED, RATIONALE FOR PROJECT DEFERRALS, AND CURRENT PROJECTED PROJECT COMPLETION DATE.

RESPONSE:

The National Harbor Substation Project, which was initially proposed in 2014 for 2018 completion, was proposed to respond to new customer additions anticipated in the National Harbor Development. Pepco recommended a one year deferral to 2019 in 2015, based on the status of construction in the development. Based on subsequent discussions between the Pepco and the developer of National Harbor, Pepco has determined that this substation should be deferred to 2021. This project schedule will be adjusted based on the developer's construction activities in National Harbor. Significant load additions in the National Harbor development will cause a firm capacity overload at Pepco's Livingston Road Substation.

SPONSOR: William M. Gausman

POTOMAC ELECTRIC POWER COMPANY
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RESPONSE TO STAFF DATA REQUEST NO. 9

QUESTION NO. 7

PAGES 9-10 - PLEASE PROVIDE A DETAILED SPECIFIC LIST OF THE PROJECTS THAT HAVE BEEN DEFERRED. FOR EACH PROJECT, PLEASE PROVIDE THE DATE THE PROJECT WAS ORIGINALLY CONCEIVED, THE DRIVER FOR THE PROJECT INCLUDING SPECIFIC EQUIPMENT THAT WAS PROJECT TO BE OVERLOADED, THE PERCENT OF THE OVERLOAD, THE NORMAL AND EMERGENCY EQUIPMENT RATINGS, THE PROJECTED LOADING ON THE EQUIPMENT AFTER THE PROJECT WAS COMPLETED, THE ORIGINAL PROJECT SERVICE DATE, ALL REVISED PROJECT SERVICE DATE(S) FOR THE PROJECT, RATIONALE FOR PROJECT DEFERRALS, AND ACTUAL PROJECT COMPLETION DATE OR SCHEDULED COMPLETION DATE.

RESPONSE:

See the attached.

SPONSOR: William M. Gausman

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Deferred Projects from 2013 - 2016 **Project**	**Originally Conceived Date**	**Driver of Project**	**% Overload**	**Firm Capacity (MVA)**	**Projected Loading after Completion**	**Original Project Service Date**	**Interim Project Service Dates**	**Scheduled Completion Date**	**Rational for Deferral**
Melwood Substation	Jun-07	Substation overload	Crain Highway Sub. 155 = 3% firm capacity overload	80.0	27.0	Jun-19	Jun-23	Jun-23	This project is contingent on significant construction in the Westphalia Town Center Development.
Replace Kingswood 20 MVA transformer with 30 MVA	Jun-10	Substation overload	Kingswood Sub. 85 = 2% firm capacity overload	79.0	72.1	Jun-15	Jun-19	Jun-17	This project was initially contingent on the Westphalia Town Center and nearby residential development. The project was subsequently advanced through the ECA Process.
White Flint/Grosvenor	Jun-12	Substation overload	Parklawn Sub. 172 = 6% firm capacity overload	80.0	46.3	Jun-18	Jun-20	Jun-20	The project was deferred in conjunction with delays in construction of projects in the White Flint area and in reduced usage.
National Harbor	Jun-14	Substation Overload	Livingston Road Sub. 151 = 5% firm capacity overload	80.0	33.0	Jun-18	Jun-21	Jun-21	This project is contingent on the National Harbor development

POTOMAC ELECTRIC POWER COMPANY
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QUESTION NO. 17

PAGE 17, TABLE 5 - PLEASE PROVIDE A DETAILED LIST OF PROJECTS FOR THE "CUSTOMER DRIVEN", "RELIABILITY PLANNED", "RELIABILITY EMERGENCY", AND " LOAD" CATEGORIES FOR EACH YEAR FROM 2016-2020. PLEASE INCLUDE NAME OF PROJECT, DESCRIPTION OF PROJECT, ESTIMATED COST FOR EACH PROJECT, DETAILED EXPLANATION OF THE DRIVERS OF THE PROJECT, AND EXPECTED COMPLETION DATE.

A. FOR THE RELIABILITY RELATED PROJECTS, PLEASE PROVIDE EXPECTED RELIABILITY BENEFIT (SAIFI/SAIDI) FOR EACH YEAR INDICATED.

B. FOR THE LOAD DRIVEN PROJECTS, PLEASE PROVIDE THE DATE THE PROJECT WAS ORIGINALLY CONCEIVED, THE DRIVER FOR THE PROJECT INCLUDING SPECIFIC EQUIPMENT THAT WAS PROJECT TO BE OVERLOADED, THE PERCENT OF THE OVERLOAD, THE NORMAL AND EMERGENCY EQUIPMENT RATINGS, THE PROJECTED LOADING ON THE EQUIPMENT AFTER THE PROJECT WAS COMPLETED, THE ORIGINAL PROJECT SERVICE DATE, ALL REVISED PROJECT SERVICE DATE(S) IF THE PROJECT WAS DEFERRED, RATIONALE FOR PROJECT DEFERRALS, AND CURRENT EXPECTED PROJECT COMPLETION DATE.

C. FOR THE CUSTOMER DRIVEN PROJECTS, PLEASE PROVIDE EXPECTED RELIABILITY BENEFIT (SAIFI/SAIDI) FOR EACH YEAR INDICATED.

RESPONSE:

Notwithstanding the objection, see the attached for available information.

A&C. The Company predicts the direct impacts on SAIFI and SAIDI on an individual project basis, but on the synergies brought by conducting all of the reliability improvement projects.

B. Due to the detailed information requested, the response to this data request will be provided by June 15, 2016.

SPONSOR: William M. Gausman

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Project ID	Items	Budget Category 02/01/16 10k Approved 2016-2020 5-Year Plan	Type of Project	REP	Current Budget 2016 ($) 02/01/16 10k Approved 2016-2020 5-Year Plan	Current Budget 2017 ($) 02/01/16 10k Approved 2016-2020 5-Year Plan	Current Budget 2018 ($) 02/01/16 10k Approved 2016-2020 5-Year Plan	Current Budget 2019 ($) 02/01/16 10k Approved 2016-2020 5-Year Plan	Current Budget 2020 ($) 02/01/16 10k Approved 2016-2020 5-Year Plan	Current Budget (2016-2020) ($) 02/01/16 10k Approved 2016-2020 5-Year Plan
UDSPRD8PM2	009 Sligo T1 B-0537 Transformer Replace (ECA) (UDSPRD8PM2)	Reliability Driven	Substation	-	2,100,000	0	0	0	0	2,100,000
UDSPRD8PM	009 Sligo T3 B-0581 Transformer Replace (ECA) (UDSPRD8PM)	Reliability Driven	Substation	-	0	2,100,000	0	0	0	2,100,000
UDSPRD8AM2	084 Palmers Corner T2 Transformer Replace (ECA) (UDSPRD8AM2)	Reliability Driven	Substation	-	5,000,000	0	0	0	0	5,000,000
UDSPRD8AM7	121 Bells Mill T1 and T9 Transformer (ECA) (UDSPRD8AM7)	Reliability Driven	Substation	-	2,750,000	840,000	1,260,000	0	0	4,850,000
UDSPRD8PM3	121 Bells Mill T10 (UDSPRD8PM3)	Reliability Driven	Substation	-	0	0	500,000	1,500,000	0	2,000,000
UDSPRD8KM	13.8kV Swgr Replacement - Pepco MD (UDSPRD8KM)	Reliability Driven	Substation	-	3,250,000	0	0	300,000	4,000,000	7,550,000
UDSPRD9KM	13kV Air Ckt Brkr Repl/Refurb: Pepco MD (UDSPRD9KM)	Reliability Driven	Substation	-	0	0	923,000	932,000	0	1,855,000
UDSPRD8JM	Animal Guards in Dist Subs: Pepco MD (UDSPRD8JM)	Reliability Driven	Substation	-	212,978	214,672	214,672	214,672	180,108	1,037,102
UDSPRD8EM	Batt & Chgr Replacement Distri. Subs. - MD (UDSPRD8EM)	Reliability Driven	Substation	-	528,481	555,373	549,221	525,322	410,000	2,568,397
UDLPCM7M	Bethesda Navy Medical Ct: Install New Fdrs ½ (UDLPCM7M)	Customer Driven	Line	-	3,340,822	0	0	0	0	3,340,822
UDLPCSLM	Bureau of Standards - Feeder Swap (UDLPCSLM)	Customer Driven	Line	N/A	200,000	0	0	0	0	200,000
UDSPLCV1	Colesville Sub: Install 3rd Transformer (UDSPLCV1)	Load Driven	Substation	Load Grow	822,349	0	0	0	0	822,349
UDLPLCV1	Colesville: Construct New Supply/13kv Fdrs (UDLPLCV1)	Load Driven	Line	Load Grow	4,939,768	0	0	0	0	4,939,768
UDLPRM4FM	Customer Reliability Improvements: Forestville (UDLPRM4FM)	Reliability Driven	Line	-	340,564	348,843	348,843	357,564	366,503	1,762,317
UDLPRM4RM	Customer Reliability Impvmts:Rockville (UDLPRM4RM)	Reliability Driven	Line	-	340,148	348,425	348,425	357,137	366,064	1,760,199
UDLPLDT1	Darnestown Sub. 225 - 69 kV Supplies (UDLPLDT1)	Load Driven	Line	Load Grow	5,462,105	3,703,308	0	0	0	9,165,413
UDSPLDT1	Darnestown Sub. 225, New 80MVA Substation (UDSPLDT1)	Load Driven	Substation	Load Grow	13,883,588	20,247,699	5,000,000	0	0	39,131,287
UDLPLM7M	Dist Feeder Load Relief - MD (UDLPLM7M)	Load Driven	Line	Load Grow	4,827,573	5,050,847	6,300,000	5,489,000	6,683,670	28,351,090
UDSPRD8FM	Dist Sub Bushing Replacement: Pepco MD (UDSPRD8FM)	Reliability Driven	Substation	-	503,580	530,511	530,511	531,000	533,000	2,628,602
UDSPRD71M	Dist. Sub. Emergency Blanket MD (UDSPRD71M)	Reliability Driven	Substation	-	800,000	800,000	814,160	818,415	1,000,000	4,232,575
UDLPRDA1M	Distribution Automation - Pepco MD (UDLPRDA1M)	Reliability Driven	Line	Distributio	1,294,946	490,727	805,573	500,000	500,001	3,591,247
UDSPLM7M	Distribution Feeder Load Relief MD (UDSPLM7M)	Load Driven	Substation	Load Grow	177,136	218,502	221,351	224,201	224,201	1,065,391
UDLPRM62M	Distribution Line Heavy Up Imprv - MD (UDLPRM62M)	Reliability Driven	Line	69kV Supp	14,244,966	9,188,856	9,188,856	6,975,186	6,975,186	46,573,050
UDLPRM32M	Emergency Restoration Primary Cable in Duct: Pepco MD (UDLPRM32M)	Reliability Driven	Line	-	1,104,177	1,003,501	1,003,501	1,500,014	1,500,000	6,111,193
UDLPLEBS	Extend Beltsville Sub. 194 feeder 14465 (UDLPLEBS)	Load Driven	Line	N/A	200,000	0	0	0	0	200,000
UDLPCSFM	Extend Beltsville Sub. 194 Feeder 14467 (UDLPCSFM)	Customer Driven	Line	Load Grow	1	1	0	0	0	2
UDSPCM7M	Extending three feeders, tape & test to Navy Medical (CVG 078) (UDSPCM7M	Customer Driven	Substation	-	1,623,965	0	0	0	0	1,623,965
UDLPRM3F1	Forestville: Emergency Restoration - OH & UG (UDLPRM3F1)	Reliability Driven	Line	-	7,064,424	7,064,406	7,064,406	7,239,789	7,487,200	35,920,225
UDLPRM4FA	Forestville: Misc Distribution Changes (UDLPRM4FA)	Reliability Driven	Line	-	967,661	1,018,839	1,018,839	1,081,939	1,114,397	5,201,675
UDLPRM4FO	Forestville: Padmount Transformer Replacements (UDLPRM4FO)	Reliability Driven	Line	-	250,559	250,651	250,651	258,171	265,916	1,275,948
UDLPRM4FD	Forestville: Planned Cable Replacement/ Curing (UDLPRM4FD)	Reliability Driven	Line	UG Reside	4,000,000	4,000,000	4,000,000	4,000,000	4,000,000	20,000,000
UDLPRM4FC	Forestville: Replace Deteriorated URD Cable (UDLPRM4FC)	Reliability Driven	Line	UG Reside	350,000	1,350,000	350,000	360,500	371,315	2,781,815
UDLPRM4FQ	Forestville: Upgrades for Multi Device Operations (UDLPRM4FQ)	Reliability Driven	Line	-	1,500,332	1,500,402	1,500,484	1,099,132	1,132,106	6,732,456
UDSPRD8AM13	GE UR Relay Replacement - MD (UDSPRD8AM13)	Reliability Driven	Substation	-	300,000	4,500,000	0	0	0	4,800,000
UDLPLGBD1	Greenbelt Station - New Supply to Development (UDLPLGBD1)	Customer Driven	Line	Load Grow	0	0	1,110,677	0	0	1,110,677
UDLPLM71	Install 3 69kV Feeders from Sligo - Linden 69KV Line (UDLPLM71)	Load Driven	Line	N/A	12,291,593	23,737,964	9,551,155	0	0	45,580,712
UDSPLM79B	Install 4th 230/69kV Tansformer # 11 at Takoma Sub (UDSPLM79B)	Load Driven	Substation	Load Grow	0	0	0	30,000	4,970,000	5,000,000
UDLPRM5SL	Install PAC Cable on 2-34kV Feeders (UDLPRM5SL)	Reliability Driven	Line	N/A	250,000	0	0	0	0	250,000
UDSPRD8SM	Install Smart Relays and Replace RTU's - MD (UDSPRD8SM)	Reliability Driven	Substation	Distributio	900,000	900,000	900,000	0	1,000,000	3,700,000
UDLPRM5EM	IR: 34 & 69kv Oil Filled Cable Replacements - MD (UDLPRM5EM)	Reliability Driven	Line	-	0	4,508,242	5,199,243	0	0	9,707,485
UDLPRM9ZR	IR: Dist Line Switch Repl: Rockville (UDLPRM9ZR)	Reliability Driven	Line	-	0	0	257,000	257,000	0	514,000
UDSPRD9M6	IR: Pepco MD - Upgrade Dist Sub Cooler Pumps (UDSPRD9M6)	Reliability Driven	Substation	-	0	0	51,000	54,000	0	105,000
UDSPLKW1	Kingswood Sub 85: Replace 20MVA Transformer with 30MVA Transformer (U	Load Driven	Substation	Load Grow	543,600	0	0	0	0	543,600
UDLPLKW2	Kingswood Sub. 85: Extend 2 new Distribution Fdrs (UDLPLKW2)	Load Driven	Line	Load Grow	4,000,000	2,500,000	5,000,000	2,000,000	0	13,500,000
UDSPLAM1	Land for Ammendale Sub (UDSPLAM1)	Load Driven	Substation	Load Grow	0	0	0	0	0	-
UDSPLLND1	Linden Sub: Install 69kV term equip for resupply from Takoma via Sligo (UDSF	Reliability Driven	Substation	N/A	175,000	600,000	250,000	0	0	1,025,000
UDLPCH0M	Maryland Highway Relocation (UDLPCH0M)	Customer Driven	Line	-	2,845,999	2,951,782	2,951,782	3,040,335	3,131,545	14,921,443
UDLPRM4MU	MD - Install Tree Wire/Spacer Cable (UDLPRM4MU)	Reliability Driven	Line	-	0	0	539,000	552,000	0	1,091,000
UDLPCS3M	MD : Facility Relocation (Non-Highway) (UDLPCS3M)	Customer Driven	Line	-	690,992	711,855	711,855	733,211	755,207	3,603,120
UDLPCS6M	MD : New Load - Network Sevices (UDLPCS6M)	Customer Driven	Line	-	994,346	1,048,434	1,048,434	1,149,887	1,184,383	5,425,484
UDLPCS2M	MD : Residential Infrastructure (UDLPCS2M)	Customer Driven	Line	-	4,883,933	3,479,666	3,479,666	3,653,649	3,836,331	19,333,245
UDLPLGV2	MD Install Three 69kV Feeders from Takoma to Sligo 69kV Line (UDLPLGV2)	Load Driven	Line	N/A	33,806,548	50,897,036	22,857,845	0	0	107,561,429
UDLPCS1M	MD: New Load - Service & Street Lights --Non - Network (UDLPCS1M)	Customer Driven	Line	-	26,258,126	24,150,964	21,967,449	20,784,941	21,085,735	114,247,215

Project ID	Items	Budget Category 02/01/16 10k Approved 2016-2020 5-Year Plan	Type of Project	REP	Current Budget 2016 ($) 02/01/16 10k Approved 2016-2020 5-Year Plan	Current Budget 2017 ($) 02/01/16 10k Approved 2016-2020 5-Year Plan	Current Budget 2018 ($) 02/01/16 10k Approved 2016-2020 5-Year Plan	Current Budget 2019 ($) 02/01/16 10k Approved 2016-2020 5-Year Plan	Current Budget 2020 ($) 02/01/16 10k Approved 2016-2020 5-Year Plan	Current Budget (2016-2020) ($) 02/01/16 10k Approved 2016-2020 5-Year Plan
UDSPRD8BM	MD:Misc. Dist Relay Upgrades (UDSPRD8BM)	Reliability Driven	Substation	-	0	0	62,000	66,000	0	128,000
UDLPRM5SM	MD:Repl Rubber/Lead Secondary Cables (UDLPRM5SM)	Reliability Driven	Line	-	150,000	150,000	150,000	154,500	159,135	763,635
UDSPLMW1	Melwood Road Sub. 224 New 120MVA Substation (UDSPLMW1)	Load Driven	Substation	Load Grow	0	0	0	50,000	4,642,590	4,692,590
UDLPLMW1	Melwood: Construct New Supply/13kv Fdrs (UDLPLMW1)	Load Driven	Line	Load Grow	0	0	0	10,000	3,290,000	3,300,000
UDLPCMR2M	Meter Blanket - AMI - Pepco MD (UDLPCMR2M)	Customer Driven	Line	-	4,589,860	3,771,450	3,846,879	3,923,816	3,923,816	20,055,821
UDLPRM4RG	Misc Dist Impvt - Mainline Heavy-Up:Rockville (UDLPRM4RG)	Reliability Driven	Line	-	30,000	0	0	0	0	30,000
UDLPRM4FG	Mist Dist Impvt Mainline Heavy-Up: Forestville (UDLPRM4FG)	Reliability Driven	Line	-	30,000	0	0	0	0	30,000
UDLPRM5FP	MODs Replacements - Forestville (UDLPRM5FP)	Reliability Driven	Line	Distributio	1,025,049	75,067	75,061	75,023	0	1,250,200
UDLPRM5RP	MODs Replacements - Rockville (UDLPRM5RP)	Reliability Driven	Line	Distributio	1,025,211	75,067	75,046	75,012	0	1,250,336
UDLPLM7PG	National Harbor Substation - Distribution Feeders (UDLPLM7PG)	Load Driven	Line	Load Grow	0	0	0	2,392,500	0	2,392,500
UDSPLNH1	National Harbor Substation - New 69/13kV Distribution Sub (UDSPLNH1)	Load Driven	Substation	Load Grow	2,586,000	10,725,000	16,089,000	6,100,000	0	35,500,000
UDLPLM7NH	National Harbor Substation - Supply Feeders (UDLPLM7NH)	Load Driven	Line	Load Grow	0	480,000	28,810,000	27,810,000	0	57,100,000
UDSPRD8VM	NERC Physical Security Pepco Dist Sub.- MD (UDSPRD8VM)	Reliability Driven	Substation	-	182,001	182,753	182,753	0	180,000	727,507
UDLPRM4MR	Network RMS - Pepco Maryland (UDLPRM4MR)	Reliability Driven	Line	Distributio	5,000	1,250,000	500,000	1,250,000	500,000	3,505,000
UDLPLM7M1	New Feeder from Campus Drive Sub. 189 (UDLPLM7M1)	Load Driven	Line	Load Grow	2,000,000	0	0	0	0	2,000,000
UDLPCACRM	New Load Accruals - MD (UDLPCACRM)	Customer Driven	Line	-	1,000	1,000	1,000	0	0	3,000
UDLPRM4A1	Pepco MD - Deteriorated Cap Bank Replace (UDLPRM4A1)	Reliability Driven	Line	-	300,000	300,000	350,000	350,000	0	1,300,000
UDLPRM4MJ	Pepco MD- Add Recloser Sectionalization (UDLPRM4MJ)	Reliability Driven	Line	Distributio	9,500,000	28,000,000	1,500,168	1,537,672	1,576,114	42,113,954
UDSPRD9M4	Pepco MD Condition Monitoring Info System (UDSPRD9M4)	Reliability Driven	Substation	-	0	0	146,000	152,000	0	298,000
UDLPRM9PM	Pepco MD Distrib - Upgrade Pumping Plants (UDLPRM9PM)	Reliability Driven	Line	-	1,425,000	50,000	53,000	54,000	55,000	1,637,000
UDLPRM63M	Pepco MD Feeder Reliability Imprv (UDLPRM63M)	Reliability Driven	Line	Feeder Imן	21,000,000	21,000,000	24,000,000	24,000,000	25,000,000	115,000,000
UDLPOSV5M	Pepco MD Reg: Salvage Scrap Wire/Cable (UDLPOSV5M)	Reliability Driven	Line	-	-25,000	-25,000	-25,000	-2,000,000	-25,000	(2,100,000)
UDSPRD8TM	Pepco MD: Roof Replacements (UDSPRD8TM)	Reliability Driven	Substation	-	194,428	130,000	130,000	130,000	0	584,428
UDSPRD8LM	Pepco MD: Substation Ventilation (UDSPRD8LM)	Reliability Driven	Substation	-	41,988	43,055	43,055	48,000	0	176,098
UDSPRD9M5	Pepco MD: Add Sub Condition Monitoring Points (UDSPRD9M5)	Reliability Driven	Substation	-	109,504	110,559	110,559	119,000	119,000	568,622
UDSPRD8M2	Pepco MD: Improve/Add Substation Enclosures (UDSPRD8M2)	Reliability Driven	Substation	-	73,614	73,998	73,998	82,093	0	303,703
-	Pepco MD: Swgr Replacement _Dist Line work	Reliability Driven	Line	N/A	1,000,000	1,250,000	2,000,000	2,000,000	0	6,250,000
UDSPCSOLM	Pepco MD:Dist Sub Work - Solar Projs (UDSPCSOLM)	Customer Driven	Substation	-	1,001	1,001	1,001	1,000	1,000	5,003
UDLPRM4FE	Pepco Reject Pole Repl/Reinf Forestville (UDLPRM4FE)	Reliability Driven	Line	-	341,085	349,681	349,681	358,423	367,384	1,766,254
UDLPRACRM	PEPCO-MD - Accrual for Reliability (UDLPRACRM)	Reliability Driven	Line	-	227,221	-933	251,117	-1,625,765	-645,542	(1,793,902)
UDSPRD8AM4	Pepco-MD: Beltsville Sub 194-Switchgear Repl (UDSPRD8AM4)	Reliability Driven	Substation	-	150,000	3,000,000	2,250,000	0	0	5,400,000
UDSPRD8AM1C	Pepco-MD: Bladensburg Sub 175-Switchgear Repl (UDSPRD8AM10)	Reliability Driven	Substation	N/A	150,000	3,000,000	2,250,000	0	0	5,400,000
UDSPRD8AM5	Pepco-MD: Lanham Sub. 149-Switchgear Repl (UDSPRD8AM5)	Reliability Driven	Substation	-	3,000,000	2,250,000	0	0	0	5,250,000
UDSPRD8AM8	Pepco-MD: Metzerott West Sub 140 -Switchgear Repl (UDSPRD8AM8)	Reliability Driven	Substation	-	0	150,000	3,000,000	2,250,000	0	5,400,000
UDSPRD8AM9	Pepco-MD: St. Barnabas Sub 59 -Switchgear Repl (UDSPRD8AM9)	Reliability Driven	Substation	N/A	0	150,000	3,000,000	2,250,000	0	5,400,000
UDLPOEMGM	Pep-MD Damage Equipment Replacements (UDLPOEMGM)	Reliability Driven	Line	-	400,000	400,000	400,000	412,000	424,360	2,036,360
UDLPRM41M	Placeholder - Future Pepco MD: OH Misc Planned Distribution Blanket (UDLPI	Reliability Driven	Line	N/A	1,000	1,000	1,000	1,000	1,000	5,000
UDLPRM42M	Placeholder - Future Pepco MD: UG Misc Planned Distribution Blanket (UDLPI	Reliability Driven	Line	N/A	515,000	30,450	546,364	562,754	579,637	2,234,205
UDLPCM71M	Placeholder - Future Reimbursable Pepco MD: OH Misc Planned Distribution I	Customer Driven	Line	N/A	1,000	1,000	1,000	1,000	1,000	5,000
UDLPCM72M	Placeholder - Future Reimbursable Pepco MD: UG Misc Planned Distribution I	Customer Driven	Line	N/A	1,000	1,000	1,000	1,030	1,061	5,091
UDLPRM4FF	PSC Priority Ckt Impvt: Forestville (UDLPRM4FF)	Reliability Driven	Line	Priority Fe	10,008,194	10,025,619	10,025,619	10,389,999	10,791,700	51,241,131
UDLPRM4RF	PSC Priority Ckt Impvts: Rockville (UDLPRM4RF)	Reliability Driven	Line	Priority Fe	10,000,092	10,000,071	10,000,071	10,330,077	10,669,980	51,000,291
UDLPCPRL1	Purple Line: Line Work for New Service (UDLPCPRL1)	Customer Driven	Line	-	0	266,707	0	0	0	266,707
UDLPRM4RE	Reject Pole Repl/Reinf: Rockville (UDLPRM4RE)	Reliability Driven	Line	-	1,055,861	1,081,149	1,081,149	1,108,178	1,135,882	5,462,219
UDLPMS5M	Removal of Poles/Transformers/SL Heads - MD (UDLPMS5M)	Reliability Driven	Line	-	200,000	200,000	200,000	205,000	210,125	1,015,125
UDSPRD8UM	Repl Eng Generators Dist Sub: Pepco MD (UDSPRD8UM)	Reliability Driven	Substation	-	100,241	100,935	100,935	101,219	152,250	555,580
UDLPRM4VF	Repl Rubber/Lead Secondary Cables: Forestville (UDLPRM4VF)	Reliability Driven	Line	-	420,554	420,246	420,246	432,853	445,838	2,139,737
UDLPRM4VR	Repl Rubber/Lead Secondary Cables: Rockville (UDLPRM4VR)	Reliability Driven	Line	-	120,146	120,006	120,006	123,606	127,314	611,078
UDSPRD9GM1	Replace 4 - 230/69kV Alis Chalmers Transformers (UDSPRD9GM1)	Reliability Driven	Substation	-	779,595	0	0	0	0	779,595
UDSPRD9GM	Replace Deteriorated Dist Transformers MD (UDSPRD9GM)	Reliability Driven	Substation	-	3,449,772	3,273,071	6,524,435	6,805,798	7,000,000	27,053,076
UDSPRD8YM	Replace Dist Sub Structures (UDSPRD8YM)	Reliability Driven	Substation	-	0	0	189,000	219,000	0	408,000
UDLPRM3R1	Rockville: Emergency Restoration - OH & UG (UDLPRM3R1)	Reliability Driven	Line	-	7,657,818	7,657,810	7,657,810	8,270,609	8,548,100	39,792,147
UDLPRM4RA	Rockville: Misc Distribution Changes (UDLPRM4RA)	Reliability Driven	Line	-	968,969	1,019,368	1,019,368	1,055,044	1,086,695	5,149,444

PLC-2

Project ID	Items	Budget Category 02/01/16 10k Approved 2016-2020 5-Year Plan	Type of Project	REP	Current Budget 2016 ($) 02/01/16 10k Approved 2016-2020 5-Year Plan	Current Budget 2017 ($) 02/01/16 10k Approved 2016-2020 5-Year Plan	Current Budget 2018 ($) 02/01/16 10k Approved 2016-2020 5-Year Plan	Current Budget 2019 ($) 02/01/16 10k Approved 2016-2020 5-Year Plan	Current Budget 2020 ($) 02/01/16 10k Approved 2016-2020 5-Year Plan	Current Budget (2016-2020) ($) 02/01/16 10k Approved 2016-2020 5-Year Plan
UDLPRM4RO	Rockville: Padmount Transformer Replacements (UDLPRM4RO)	Reliability Driven	Line	-	250,559	250,651	250,651	258,171	265,916	1,275,948
UDLPRM4RD	Rockville: Planned U (UDLPRM4RD)	Reliability Driven	Line	UG Reside	5,000,000	5,000,000	5,000,000	5,000,000	6,631,627	26,631,627
UDLPRM4RC	Rockville: Replace Deteriorated URD Cable (UDLPRM4RC)	Reliability Driven	Line	UG Reside	50,000	50,000	50,000	51,000	52,020	253,020
UDLPRM4RQ	Rockville: Upgrades for Multi Device Operations (UDLPRM4RQ)	Reliability Driven	Line	-	1,008,675	1,016,756	1,024,842	515,398	530,860	4,096,531
UDSPRD9SN	Rossmoor Sub 169 Replace T1,T2,T3 (UDSPRD9SN)	Reliability Driven	Substation	-	650,587	0	0	0	0	650,587
UDSPLSG2	Sligo Sub: Install 69kV Term Equip for 3 new Takoma to Sligo feeders (UDSPLS	Reliability Driven	Substation	N/A	84,642	1,011,828	590,222	0	0	1,686,692
UDSPLM76A	Sligo Sub: Install 69kV Term Equip from Sligo to Linden (UDSPLM76A)	Load Driven	Substation	-	30,000	100,000	400,000	0	0	530,000
UDLPLSG2	Sligo: Replace 34kV circuit with 69kV circuit (UDLPLSG2)	Load Driven	Line	Load Grow	0	0	0	3,000,000	0	3,000,000
UDLPCSFRCU	SMECO Farmington Road Capacity upgrade - line (UDLPCSFRCU)	Customer Driven	Line	-	-988,613	0	0	0	0	(988,613)
UDSPCSMEM	SMECO Farmington Road Capacity upgrade - Sub (UDSPCSMEM)	Customer Driven	Substation	-	1	1	0	0	0	2
UDLPCSOLM	Solar Projects Pepco MD: Dist Lines (R) (UDLPCSOLM)	Customer Driven	Line	-	1	1	1	0	0	3
UDSPRD8GM	Spare Distrib XFMR - MD (UDSPRD8GM)	Reliability Driven	Substation	-	4,491,226	0	0	0	4,500,000	8,991,226
UDSPRD8Q1M	SPCC - Distribution Oil Brkr Replacements : Pepco MD (UDSPRD8Q1M)	Reliability Driven	Substation	-	759,268	0	0	0	0	759,268
UDLPLAN1	Sub 178 & Sub 149: Extend Feeders (UDLPLAN1)	Load Driven	Line	Load Grow	0	0	0	1,800,509	1,705,080	3,505,589
UDSPRD8AM6	Sub.075 Wheaton T2 Transformer Replacement (ECA) (UDSPRD8AM6)	Reliability Driven	Substation	-	0	2,100,000	0	0	0	2,100,000
UDSPRD8AM12	Sub.075 Wheaton T3 Transformer Replacement (ECA) Voltage:69/13kV - Size:	Reliability Driven	Substation	-	1,100,000	1,000,000	0	0	0	2,100,000
UDSPRD8AM11	Sub.85 Replace Kingswood Transformer T1 B-0765 (ECA) (UDSPRD8AM11)	Reliability Driven	Substation	-	1,000,000	1,100,000	0	0	0	2,100,000
UDSPRD8AM	Substation Improvements and Additions - MD (UDSPRD8AM)	Reliability Driven	Substation	-	73,614	107,364	108,182	109,002	0	398,162
UDSPLGV3	Substation Work at Takoma for New Linden Supplies Via Sligo (UDSPLGV3)	Load Driven	Substation	N/A	157,260	543,988	594,438	0	0	1,295,686
UDSPRD8WM	Surge Arrester Replacement - MD (UDSPRD8WM)	Reliability Driven	Substation	-	0	0	96,000	99,000	0	195,000
UDSPLM720C	Takoma 69kV Rebuild (UDSPLM720C)	Load Driven	Substation	-	0	0	0	0	474,000	474,000
UDLPRM4MA	UG Feeder 14248&14250 Heathermore Blvd (UDLPRM4MA)	Reliability Driven	Line	N/A	0	1,000,000	1,750,000	0	0	2,750,000
UDLPCWH1	Wheaton Sub. 75 - Holy Cross Hospital Express Feeders (UDLPCWH1)	Customer Driven	Line	-	-458,000	0	0	0	0	(458,000)
UDLPLGV1	White Flint Area Sub. Distribution Feeders (UDLPLGV1)	Load Driven	Line	Load Grow	0	4,204,314	5,400,000	0	0	9,604,314
UDSPLGV2	White Flint New Substation 69/13kV (UDSPLGV2)	Load Driven	Substation	Load Grow	6,734,802	19,958,005	13,756,711	0	0	40,449,518
UDLPLGV3	White Flint Sub: Construct New Supply Lines (UDLPLGV3)	Load Driven	Line	Load Grow	0	2,000,000	0	0	0	2,000,000
		TOTAL			274,756,486	331,395,544	274,651,967	188,984,586	167,550,810	1,237,339,393

POTOMAC ELECTRIC POWER COMPANY
MARYLAND CASE NO. 9418
RESPONSE TO STAFF DATA REQUEST NO. 9

QUESTION NO. 38

PLEASE PROVIDE A DETAILED LIST OF THE MARYLAND TRANSMISSION AND DISTRIBUTION FACILITIES PROJECTS THAT WERE ELIMINATED.

A. FOR EACH PROJECT, PLEASE PROVIDE THE DATE THE PROJECT WAS ORIGINALLY CONCEIVED, THE DRIVER FOR THE PROJECT INCLUDING SPECIFIC EQUIPMENT THAT WAS PROJECT TO BE OVERLOADED, THE PERCENT OF THE OVERLOAD, THE NORMAL AND EMERGENCY EQUIPMENT RATINGS, THE PROJECTED LOADING ON THE EQUIPMENT AFTER THE PROJECT WAS COMPLETED, THE ORIGINAL PROJECT SERVICE DATE, ALL REVISED PROJECT SERVICE DATE(S) IF THE PROJECT WAS DEFERRED, RATIONALE FOR PROJECT DEFERRALS, AND CURRENT SCHEDULED PROJECT COMPLETION DATE.

B. ARE ANY OF THE DESCRIBED TRANSMISSION PROJECTS IN THE PJM QUEUE? IF SO, PLEASE PROVIDE QUEUE NUMBER.

RESPONSE:

Pepco has not fully eliminated any projects from either the distribution or transmission capital budgets because of AMI. See the attachment provided to Staff DR 9-7.

SPONSOR: William M. Gausman

POTOMAC ELECTRIC POWER COMPANY
MARYLAND CASE NO. 9418
RESPONSE TO OPC DATA REQUEST NO. 16

QUESTION NO. 7

REFERENCING PEPCO RESPONSE TO STAFF DR 6-1, ATTACHMENT N, TAB, "DIST CALC – FUTURE 10 YRS" PLEASE:

A. PLEASE PROVIDE THE FORECAST MODEL AND ALL SUPPORTING WORKSHEETS USED TO DERIVE THE "PREDICTED MARYLAND LOAD" AND THE LOAD GROWTH ESTIMATE.
B. PLEASE CLARIFY IF VALUE USED FOR 2014 PREDICTED LOAD WAS ACTUAL OR PREDICTED.
C. PROVIDE THE PEPCO LOAD GROWTH VALUES FOR 2012 AND 2013.
D. PLEASE PROVIDE ALL WORKSHEETS THAT CELL K19 IS USED AS AN INPUT.
E. PLEASE PROVIDE ALL WORKSHEETS THAT CELL K21 IS USED AS AN INPUT.

RESPONSE:

A. See OPC DR 16-7 Attachment Confidential.

B. Predicted.

C. Pepco predicted load growth from 2012 to 2013 was 61 MVA and the predicted load growth from 2013 to 2014 was 40 MVA.

D. Cell K19 was not used as an input in any worksheet.

E. Cell K21 was not used as an input in any worksheet.

SPONSOR: William M. Gausman

POTOMAC ELECTRIC POWER COMPANY
MARYLAND CASE NO. 9418
RESPONSE TO OPC DATA REQUEST NO. 16

QUESTION NO. 18

FOR EACH 500 KV AND 230 KV TRANSMISSION LINE, PLEASE PROVIDE THE FOLLOWING DATA FOR YEAR, 2010 THROUGH 2015:

A. THE CAPACITY OF THE LINE.
B. THE MAXIMUM LOAD ON THE LINE.
C. THE BOOK VALUE OF THE LINE.
D. THE INSTALLATION DATE OF THE LINE.
E. THE BOOK VALUE OF THE LINE IN THE YEAR IT WAS INSTALLED.
F. THE DATE AND TIME OF THE MAXIMUM LOAD ON THE LINE.
G. THE LOAD ON THE LINE IN EACH EVENT HOUR ON EACH PEAK ENERGY SAVINGS CREDIT (PESC) AND PJM EMERGENCY EVENT IN THE YEAR.

RESPONSE:

A See MD 9418 OPC DR 16-18 Attachment A Confidential.
B. See MD 9418 OPC DR 16-18 Attachment A Confidential.
C. See MD 9418 OPC DR 16-18 Attachment B.
D. See MD 9418 OPC DR 16-18 Attachment B.
E. Many of these lines have had replacements over their lives. As assets are retired and replaced the value of the original asset is removed from the asset records and the replaced asset value is added. The value of the line at the date of installation is not available.
F. See MD 9418 OPC DR 16-18 Attachment A Confidential.
G. See MD 9418 OPC DR 16-18 Attachment C (provided electronically).

SPONSOR: Karen R. Lefkowitz/William M. Gausman

POTOMAC ELECTRIC POWER COMPANY
MARYLAND CASE NO. 9418
RESPONSE TO OPC DATA REQUEST NO. 16

QUESTION NO. 24

PLEASE PROVIDE THE DATE, TIME AND MEGAWATT LOAD FOR THE ALL-TIME PEAK DEMAND ON EACH DISTRIBUTION SUBSTATION.

RESPONSE:

Please refer to the response provided to OPC DR 16-7 (a) for the available information.

SPONSOR: William Gausman