STATE OF MARYLAND

BEFORE THE PUBLIC SERVICE COMMISSION

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

REBUTTAL TESTIMONY OF

PAUL CHERNICK

ON BEHALF OF

THE OFFICE OF PEOPLES COUNSEL

Resource Insight, Inc.

AUGUST 15, 2016

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Q: Are you the same Paul Chernick who filed direct testimony in this proceeding?

A: Yes.

Q: What is the subject of your rebuttal testimony?

A: In this testimony, I respond to the direct testimony of Staff witnesses Daniel Hurley and Mikhail Ratushny and provide updates to my direct testimony.

I. Response to Staff Testimony

Q: What is the scope of your response to Staff's direct testimony?

A: I agree with many of Staff's observations and recommendations. My rebuttal focuses on those areas where I identify important errors or oversights in Staff's analysis.

Q: To which issues in Mr. Ratushney's direct do you respond?

A: Mr. Ratushney touches on a number of operational benefits that Pepco claims for the Advanced Metering Infrastructure ("AMI") system. His skepticism regarding Pepco's claims generally appears to be warranted. I will only address in detail the issues of avoided transmission and distribution capital expenses and avoided cost of overloaded line transformers.

Q: What is your assessment of Mr. Ratushney's analysis of Pepco's claims regarding avoided transmission and distribution investments?

A: I agree with Mr. Ratushney's analysis that Pepco has overstated avoided transmission and distribution ("T&D"), OPRs 20–25, and the benefits of the line-transformer load-monitoring program, OPRs 15–17.

Q: To which issues in Mr. Hurley's direct do you respond?

A: I will address the following subset of the issues covered by Mr. Hurley's direct:

- Capacity price mitigation from cleared resources and demand reductions;[1]
- Energy revenue;
- Energy price mitigation;
- Energy avoided costs; and
- Avoided capacity cost.

In parts of his review, Mr. Hurley simply notes whether Pepco's claimed benefits resemble computations that were included in prior filings that have been accepted by the Commission. I will not deal with most of those procedural comments, concentrating instead on factual issues.

A. Avoided Transmission and Distribution Costs

Q: What was the scope of Staff's review of Pepco's estimate of transmission and distribution capital cost savings?

A: Mr. Ratushny observes, as I did in my direct, that there were no T&D projects avoided in the years relevant to benefit calculations; Pepco AMI-demand reduction programs do not reduce loads at the times of substation peak hours or at time of transmission-line peak hours (Chernick Direct at p. 52). In addition to my observations, Mr. Ratushny identifies Pepco errors in:

- the lack of a probabilistic failure assessment;
- overstatement of outage costs;
- claiming savings prior to the beginning of the transformer replacement program in 2016; and

[1] Mr. Hurley discusses "Capacity Price Mitigation" (by which he apparently means price mitigation from cleared capacity) on p. 16 and "Capacity Price Mitigation – Demand" on p. 23.

- underestimation of useful transformer life (Ratushney Direct pp. 20–21).

Q: Does Mr. Hurley accept Mr. Ratushny's T&D recommendations?

A: Yes. Mr. Hurley incorporates Mr. Ratushney's recommendations in his direct testimony, setting avoided transmission and distribution capital cost savings (OPR 20–25) to zero (Hurley Direct at p. 30).

Q: Is Mr. Ratushney's assessment of Pepco's claimed T&D benefits reasonable?

A: Yes, for the most part. He is correct that Pepco cannot identify any T&D facilities that have been deferred due to AMI to date, or whose projected deferral could be traced to AMI. His exclusion of all the claimed T&D deferral benefits for the Dynamic Pricing program ("DP"), which does not reliably reduce loads at the times that would defer investment, is also reasonable.

If the Energy Management Tools ("EMT") and Conservation Voltage Reduction ("CVR") programs actually reduce peak demands, it is likely that they would contribute in some small way to some T&D deferrals at some point in the future. Since the vast bulk of the EMT and CVR savings could be achieved without the AMI investment, omitting these savings from the cost-benefit analysis is reasonable. (Chernick Direct at 52).

Q: Did Mr. Ratushny identify all the problems with Pepco's T&D analysis?

A: No. Mr. Ratushny did not catch Pepco's error in its computation of carrying costs for the hypothetical avoided T&D, as discussed on p. 46 of my direct.

B. Line Transformers

Q: What are Mr. Ratushney's conclusions regarding Pepco's claimed benefits for avoided load-related failures?

A: With regard to Pepco's OPR benefits 15, 16 and 17, Mr. Ratushny notes that Pepco is claiming annual benefits for avoiding load-related failure of more transformers than have actually failed in recent years (Ratushny Direct at 24). I agree with his conclusion that the number of avoided failures is greatly overstated. Only 18 load-related failures occurred in 8 years (Ratushney direct at 18, Pepco Response to Staff DR 4-36bb Att.), or 2.25/year, compared to Pepco's claimed 315 historical annual failures (Pepco Response to Staff DR 4-17).[2]

It appears that Pepco would be replacing about 17 heavily-loaded (but not failing) transformers for each avoided overload-related failure. While there may be other benefits of early replacement of heavily-loaded transformers, those benefits are probably much lower than Pepco estimated for these OPR categories.

Q: Do you have any other observations regarding Pepco's claimed line-transformer benefits?

A: Yes. In reviewing Pepco's spreadsheets to verify the errors identified by Mr. Ratushny, I noticed two other problems with the computation of OPR 15–17. First, Pepco based its estimate of the value of OPR 15 by assuming that the average overload-related outage avoided by the transformer-monitoring

[2] Even if the cause were expanded to "equipment failure" of the transformer, that would add only 15 events in 8 years, of which two are probably disconnections during repair of a neighboring transformer. Pepco Response to Staff DR 4-17 can be found in Ex. PLC-R-1.

program would have lasted 4 hours (Pepco Response to Staff DR 4-27)[3], but the duration for the 18 load-related outages averaged just 2.8 hours, not the 4 hours assumed by Pepco (Pepco Response to Staff DR 4-36bb Att.).[4]

Second, the computations in Staff DR 6-1 Attachment C for OPRs 15–17 assume that Pepco would replace 350 transformers annually, and all of them would have failed by 2025. For the transformers replaced in 2016, Pepco assumes that 35 would have failed in each year 2016–2025; other than the fact that this one year of the program would be avoiding twice Pepco's total load-related failures, Pepco's approach to projected avoided annual failures seems reasonable. But for later years, Pepco assumes much less realistic failure patterns. Pepco assumes that the 2017 replacements would avoid 70 failures in 2017 and 35 each subsequent year; the 2018 replacements, 105 failures in 2018 and 35 each subsequent year; the 2019 replacements 140 failures in 2019 and 35 each subsequent year; and so on, up to the 2023 replacements, which Pepco assumes would avoid 280 failures in 2023. Pepco treats the replacements in 2016–2023 as avoiding 525 failures in 2023. Pepco winds up assuming that 2,240 failures would be avoided in 2016–2023, an average of 280 failures annually, even while the program is being phased in. Thus, PEPCo unreasonably assumed that the transformer program would avoid an *average* of 100 times as many load-related failures as have actually occurred.

[3] Ex. PLC-R-1.

[4] Interestingly, the transformer "equipment failures" lasted at least 89 minutes, suggesting that some of the load-related outages with shorter durations were limited to replacing a fuse or other simple repair.

C. Capacity Price Mitigation and Avoided Capacity Costs

Q: What were Mr. Hurley's conclusions regarding Pepco's estimates of capacity price mitigation from demand reductions?

A: Mr. Hurley recommends that CVR and EMT capacity-price-mitigation benefits and avoided-cost benefits for CVR, EMT and DP be set to zero (Hurley Direct at pp. 38–45).[5] These savings categories result when a reduction in metered load in the Pepco zone reduces PJM's forecast of Pepco zonal load for future years, starting four years later. Mr. Hurley acknowledges that "there is uncertainty as to how PJM will adjust its load forecast in response to demand reductions caused by demand side management type programs" (Hurley Direct at pp. 39, 40, 43, 44). He also recommends that the Commission require that Pepco file a report similar to that required of BGE in Case No. 9406, describing Pepco's plans to work with PJM on how the demand-side reduction affect PJM load forecasts (ibid at 39, 40, 42, 44, 45).

Q: Do you agree with Staff's assessment of the capacity price mitigation benefits of the CVR and EMT programs?

A: For the most part. The CVR and EMT programs may have some effect on capacity prices and capacity obligations, but as I explain in my direct testimony (at p. 28, 34) and in Section II.A, those will be much smaller than Pepco assumes.

Q: Do you agree with Staff's assessment of the capacity price mitigation benefits from the DP program?

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[5] Pepco did not include any avoided capacity costs from demand reductions due to the DP program.

A: No. Mr. Hurley accepts PEPCo's estimate of capacity price mitigation from the DP capacity bid into the PJM capacity market. In Section VI.C of my direct, I explained why this estimate is grossly exaggerated.

Mr. Hurley explained that, for "DSM 6–DP Capacity Price Mitigation, …the amount of the benefit is calculable after the capacity auction takes place and the slope of the appropriate [variable resource requirement] curve is known and the amount of the dynamic pricing resources have cleared." (Hurley Direct at p. 32) He omits the fact that the actual price mitigation due to the DP program depends on information that PJM does not release publically, including the detailed shape of the supply curve and the interactions among the PJM load zones and among types of capacity. Mr. Hurley is correct that the benefit is calculable, but only PJM can calculate the benefit of specific resources. In my direct testimony (at p. 39), I used PJM's reports on the effect of resources on capacity prices to provide more realistic estimates of the sensitivity of capacity prices to resources.

In addition, Mr. Hurley forgot to correct Pepco's estimate of capacity price mitigation from DP for the fact that demand response (including the DP program) cleared separately from normal generation capacity in 2014/15, 2015/16 and 2018/19, and thus had little effect on the capacity prices charged to Maryland customers.

With these corrections (and a couple smaller ones), I estimated in my direct testimony (Table 13) that the benefits for Maryland consumers of the DP load reductions would be about $15 million, just 10% of the value Mr. Hurley accepts.

D. Energy Price Mitigation

Q: What was the scope of Mr. Hurley's review of Pepco's estimate of energy price mitigation benefits?

A: Mr. Hurley limits his review of Pepco's energy price mitigation benefit to the regression model from which Pepco derived a price effect of $1.42/MWh.

Q: What were Mr. Hurley's conclusions regarding Pepco's claimed energy price mitigation benefits?

A: Mr. Hurley says that "Staff has reviewed the regression model developed by the Company and can not determine any issues or problems." (Hurley Direct at p. 33). He does not question Pepco's claims for energy price mitigation benefits from any of the programs.

Q: Do you agree with the scope of Mr. Hurley's review of the energy price mitigation benefits?

A: No. Mr. Hurley did not describe how Staff reviewed Pepco's price mitigation estimates, including the assumption that only Maryland load affects prices in any of the Maryland zones. He does not even recognize any effect of Delaware load on Delmarva prices, Virginia or West Virginia load on AP prices, or DC load on Pepco prices. As I show in my direct testimony (at pp. 35–36), regressions that recognize the effect of loads in the entire Pepco, AP and Delmarva zones, as well as in other zones, produce regression coefficients about 60% lower than Pepco's. The estimate of energy price mitigation is directly proportional to the regression coefficients, so Pepco's estimate of this benefit should be reduced 60%.

E. Energy Revenue

Q: What was the scope of Mr. Hurley's review of Pepco's estimate of energy revenue?

A: Mr. Hurley's review of the energy revenue is confusing (Hurley Direct at p. 28). In discovery, Mr. Hurley said that "The Company estimated the present value of energy savings at $1.5 million" (Staff Response to OPC DR 3-2A) and clarified that his value for OPR 19 combined the Pepco's estimates of the DP energy revenues from OPR 19 with the DP avoided energy costs from DSM 09 (Staff Response to OPC DR 2-3 a and b).[6]

Mr. Hurley noted, as I did in my direct (at 54), that Pepco had roughly doubled its estimate of DP energy savings in 2016, and corrected that error by reducing DP energy savings for 2016–2023 to be consistent with those in 2015. He also reduced DP energy savings by 10%, to reflect load shifting from the Peak Energy Savings Credit ("PESC") hours to earlier and later hours.[7]

Q: Did Mr. Hurley modify Pepco's analysis of DP energy revenues in any other manner?

A: Yes. While Mr. Hurley reduced Pepco's estimate of DP energy savings, he also assumed that the DP energy savings would both earn energy revenues and reduce energy requirements in each year from 2016 to 2023, resulting in his assumption that, in each of those years, the customer savings (DSM 09) and the Pepco revenues (OPR 19) would have the same dollar value. Pepco

[6] Ex. PLC-R-1.

[7] I made other corrections to the energy analysis, as well.

recognized that claiming savings for both categories would be double-counting, and included OPR 19 through 2015 and DSM 09 for 2016–2023.

Mr. Hurley appears to have missed this nuance, since in response to a question "Please state whether this discussion refers to OPR 19, or some other benefit(s), and if so, which ones," he explained that "[f]or the purpose of this analysis, Mr. Hurley calculated OPR 19 out to 2023 . . . [t]his value combines the benefit categories OPR 19 and DSM 9." (Staff Response to OPC DR 2-1a).[8] In other words, Mr. Hurley counted the benefits of DSM 9 in one line, and both OPR 19 and DSM 09 in another, and added them together.

As a result, Mr. Hurley estimates a benefit of $731,000 for OPR 19 and $676,000 for DSM 09, for a combined benefit of $1.4 million. Without the double-counting, his estimate would have been $0.7 million.

II. Updated Analysis

Q: What areas of your direct testimony can you now update?

A: I have received the following information that allows me to update portions of my direct testimony:

- PJM's response regarding the effectiveness of Pepco's AMI-related load reductions in reducing PJM's load forecasts; and
- Pepco's customer-specific hourly load data for summer weekdays for hours 15–18.

[8] The response continued by saying "Mr. Hurley did not include a value for DSM in his testimony." It is not clear what this statement means. Staff Response to OPC DR 2-1a can be found in Ex. PLC-R-1.

A. PJM Estimates of the Effects of Pepco Load Reductions on Pepco's Load Forecast

Q: What additional information can you provide the Commission regarding the effective of Pepco's AMI-related load reductions on PJM's load forecasts?

A: As I stated in my direct (at p. 30), I asked PJM to rerun its 2016 Load Report regression equations and forecast for the RTO and Pepco with the following increases in Pepco's contribution to RTO daily peak:

1. Increasing each peak by 0.83% in 2013, 2014 and 2015, to model the forecast increase if the uniform reductions that Pepco claims for the CVR and EMT programs had not existed.

2. Increasing load on the PESC days by Pepco's estimate of the DP savings, as shown in Table 1, to roughly model the effect if the DP program had not existed.

Table 1: DP Load Reductions

Event Date	MW
7/21/2015	151
7/30/2015	242
8/3/2015	135
9/9/2015	158
6/18/2014	125
8/27/2014	216
9/2/2014	188
8/21/2013	96
9/11/2013	125

Q: What results did PJM provide?

A: Table 2 shows the base forecasts and the effects of the removing Pepco's claimed savings from the PJM forecast for Pepco zone contribution to PJM annual peak. Each megawatt of DP load reduction in 2013–2015 results in only about 0.02 MW of reduction in the forecast; each megawatt of uniform

load reduction from the CVR or EMT program would reduce the forecast by 0.2 to 0.3 MW.[9] Thus, Pepco's estimate that the AMI programs would reduce capacity obligation megawatt for megawatt is wrong; the avoided capacity obligation would be about 2% of the DP load reduction and 20%–30% of the CVR and EMT load reductions.

Table 2: Effect of Load Reductions on PJM Forecast of Pepco Load at PJM Peak

	Official 2016 Forecast	+0.83% 2013–15	DP Adjustment	MW Change with +0.83%	MW Change with DP Adj	Forecast Change as % Load Change +0.83%	Forecast Change as % Load Change DP Adj
2016	6,288	6,298	6,291	11	4	20.6%	2.2%
2017	6,333	6,346	6,337	13	4	24.3%	2.4%
2018	6,353	6,369	6,356	16	2	30.0%	1.5%
2019	6,387	6,401	6,390	14	3	25.9%	2.1%
2020	6,415	6,431	6,419	16	3	29.3%	2.1%
2021	6,404	6,419	6,407	15	3	27.9%	1.9%
2022	6,384	6,398	6,387	15	4	27.8%	2.3%
2023	6,407	6,423	6,411	16	4	30.4%	2.5%

Table 3 provides a similar summary of the PJM results for the PJM forecast, which are very similar to the results for the Pepco forecast. The PJM system forecast falls by 2% of the DP program reductions and 21%–30% of the CVR and EMT program reductions. Thus, the capacity price mitigation would be much smaller than Pepco estimates, even if the rest of its computation were correct. One megawatt of AMI load reduction shifts the PJM capacity demand curve by much less than one megawatt.

[9] I did the computation using the average load reduction at the PJM peak hour.

Table 3: Effect of Load Reductions on PJM Peak Forecast

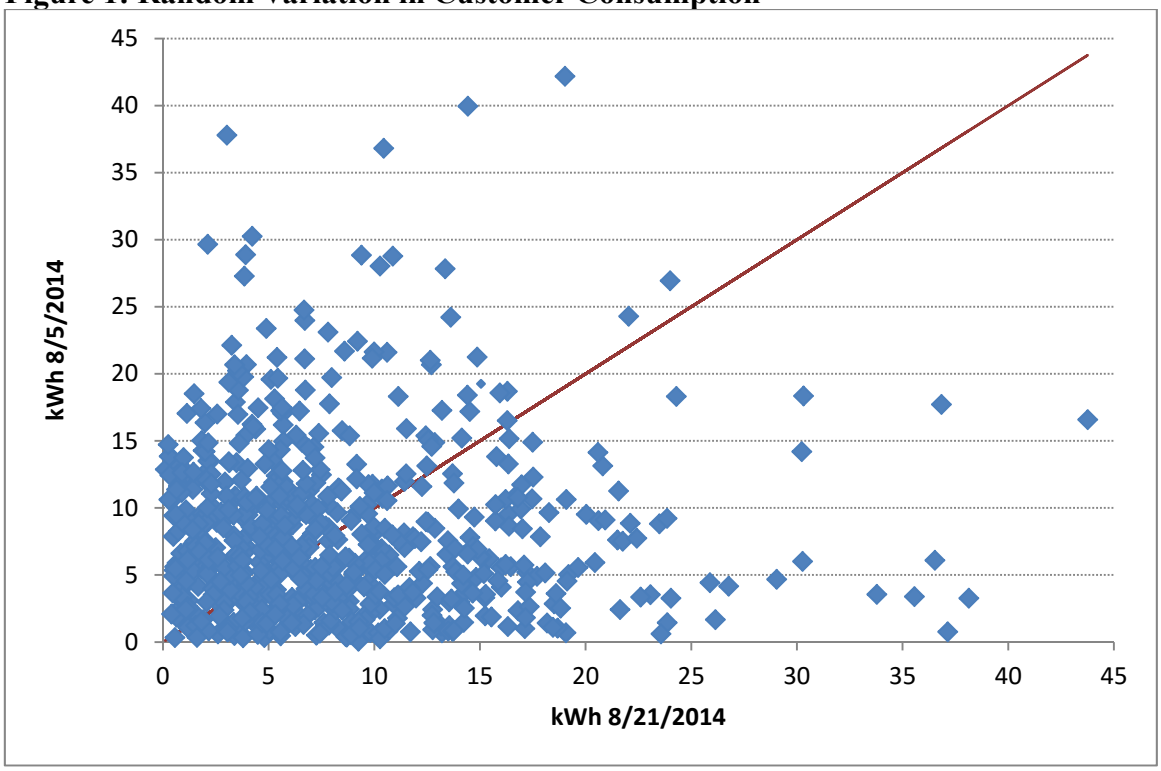
	Official 2016 Forecast	+0.83% 2013–15	DP Adjustment	MW Change with +0.83%	MW Change with DP Adj	Forecast Change as % Load Change +0.83%	Forecast Change as % Load Change DP Adj
2016	152,131	152,142	152,134	11	3	21.3%	1.9%
2017	154,149	154,162	154,152	13	3	24.8%	1.7%
2018	155,913	155,926	155,916	13	3	25.3%	2.0%
2019	156,958	156,972	156,961	14	3	26.5%	2.0%
2020	156,887	156,901	156,890	14	3	26.8%	2.0%
2021	157,358	157,373	157,362	15	3	27.6%	2.0%
2022	157,986	158,002	157,990	15	3	28.7%	2.0%
2023	158,975	158,991	158,978	16	3	29.8%	2.0%

B. Random Scatter in the Pepco Residential Load

Q: What additional information can you provide the Commission regarding what has been called free-ridership in the DP program, due to the variation in individual residential customers' loads, from one hot day to another, without any PESC incentives?

A: As I promised in my direct (at p. 20), I have looked at data Pepco provided on the hourly loads of a sample of individual customers (provided in Pepco Response to OPC DR 8-25). In Figure 1, I plot the energy use of 9,650 residential customers in the PESC hours on two non-PESC days, August 5 and August 21, 2014. I selected those dates due to their similarly high weighted temperature and humidity index ("WTHI") weather variables (78.8° and 79.1°, respectively).

Figure 1: Random Variation in Customer Consumption



Each data point represents a single customer's load on August 5 (vertical axis) and August 21 (horizontal axis). Customers below the red line used more energy on August 21, those above used more energy of August 5.

In this sample, 4,329 customers used more on August 21, 2014, averaging 2.5 kWh more apiece than on August 5, while 5,321 customers used more on August 5, averaging 2.7 kWh more than on August 21. If Pepco had decided that August 21 would be a PESC day, but forgot to tell the public, and August 5 were used as a baseline, Pepco would throw out the 4,329 customers who used more on August 21 as non-participants, conclude that the 5,321 engaged participants in the DP program responded by reducing usage 2.7 kWh apiece, and would have claimed 14.4 MWh of savings without any actual customer response.

The same problem would have arisen if the August 5 weather and other circumstances had occurred after the August 21 circumstances. In that case,

Pepco would have ignored the 5,321 participants whose usage increased, claim 4,329 participants with 2.5 kWh of average savings, and 10.6 MWh of savings, again without any customer response.

Q: What do you conclude from this analysis?

A: For any pair of hot days, random variation in customer usage, combined with Pepco's decision to ignore customers who increase load, will create the appearance of substantial response to any program that targets one day and not the other, independent of any actual customer response to the program.

Q: Would this result be affected by either the use of three days in Pepco's baseline for determining whether customers would be considered participants, or Brattle's weather-adjustment of the "participant" loads?

A: The averaging of loads over the three days from which Pepco develops the baseline consumption would reduce this effect somewhat. In contrast, Brattle's temperature adjustment would generally have little effect on the savings estimate.

Much of the demand and energy reductions estimated by Pepco are artifacts of these random variations in customer usage, which Pepco's analysis does not identify or remove from its estimates of load reductions. My review of this data confirms that Pepco's estimates of DP load reductions are overstated and must be substantially reduced, as I did in my direct.

Q: Does this conclude your rebuttal testimony?

A: Yes.

Data Requests Cited in Testimony

PLC-R-1

POTOMAC ELECTRIC POWER COMPANY
MARYLAND CASE NO. 9418
RESPONSE TO STAFF DATA REQUEST NO. 4

QUESTION NO. 17

WHAT IS FAILURE RATE OF OVERLOADED TRANSFORMERS FOR THE LAST 10 YEARS?

RESPONSE:

The Company has estimated that an average of 315 transformers failed annually due to overload during the period of 2011-2013. The Company has not analyzed the transformer failures that are specifically due to overloads over the past 10 years.

SPONSOR: Karen R. Lefkowitz

POTOMAC ELECTRIC POWER COMPANY
MARYLAND CASE NO. 9418
RESPONSE TO STAFF DATA REQUEST NO. 4

QUESTION NO. 27

HOW DID PEPCO DETERMINE THE AVOIDED OUTAGE DURATION PERIOD? (THE DIFFERENCE BETWEEN A FORCED OUTAGE AND A PLANNED OUTAGE). WHAT WAS JUSTIFICATION FOR ASSUMPTION THAT IF THE AVOIDED OUTAGE DURATION CAN BE AS LARGE AS 14 HOURS, IT IS ASSUMED THERE WOULD BE A REDUCTION OF FOUR HOURS IN OUTAGE DURATION?

RESPONSE:

The Company made a conservative assumption that there will a four-hour average difference between the planned transformer replacement and emergency replacement after the failure. The basis for the assumption is avoidance of several necessary steps associated with a forced outage; the time it takes for the initial trouble crew to assess the cause for the outage and make the recommendations, equipment staging, and any potential spill cleanup efforts.

The longer outages are typically associated with underground transformer failures. The four-hour difference between a forced and a planned outage is an average figure regardless of the actual duration of individual outages.

SPONSOR: Karen R. Lefkowitz

OPR 15 **Improved Operation of Assets and Reliability**

Input Assumptions

a	No of transformer replacements/year	350
b	All in Weighted Average Cost for a replaced transformer	$ 4,175
c	Expected life for overloaded transformer (years)	10
d	Expected life for a non-overloaded transformer (years)	40
e	Pepco-MD customer count	533,642
f	Pepco-MD transformer count	86,768
g	Carrying Charge% [3]	10.40%

Intermediate Calculation

(Weighted outage cost/customer: 4 hour sustained outage)

	4 Hour Sustained Outage
Residential	
Cost of outage per customer	$ 9.50
Total Number of Customers	486,059
Small C&I	
Cost of outage per customer	$ 1,880.00
Total Number of Customers	29,962
Medium and Large C&I	
Cost of outage per customer	$ 39,458.00
Total Number of Customers	17,621

a Weighted average cost of outage per customer $ 1,417

b **No of customers/transformer** 6 → Input assumptions"e"/Input assumptions"f"

c **Annual Unadjusted Pepco-MD benefit** 2,975,955 → Intermediate Calculation "b" *Intermediate Calculation 'a"*Input assumption"a"

d **Adjusted Benefits/year**

	2016	2017	2018	2019	2020	2021	2022	2023	Outside the evaluation period 2024	2025
Failed Transformer Proportion [1]	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
2016 transformer replacements benefits	$ 297,596	$ 297,596	$ 297,596	$ 297,596	$ 297,596	$ 297,596	$ 297,596	$ 297,596	$ 297,596	$ 297,596
2017 transformer replacements benefits		$ 595,191	$ 297,596	$ 297,596	$ 297,596	$ 297,596	$ 297,596	$ 297,596	$ 297,596	$ 297,596
2018 transformer replacements benefits			$ 892,787	$ 297,596	$ 297,596	$ 297,596	$ 297,596	$ 297,596	$ 297,596	$ 297,596
2019 transformer replacements benefits				$ 1,190,382	$ 297,596	$ 297,596	$ 297,596	$ 297,596	$ 297,596	$ 297,596
2020 transformer replacements benefits					$ 1,487,978	$ 297,596	$ 297,596	$ 297,596	$ 297,596	$ 297,596
2021 transformer replacements benefits						$ 1,785,573	$ 297,596	$ 297,596	$ 297,596	$ 297,596
2022 transformer replacements benefits							$ 2,083,169	$ 297,596	$ 297,596	$ 297,596
2023 transformer replacements benefits								$ 2,380,764	$ 297,596	$ 297,596
2024 transformer replacements benefits									$ 2,678,360	$ 297,596
2025 transformer replacements benefits										$ 2,975,955
Total Benefits	$ 297,596	$ 892,787	$ 1,487,978	$ 2,083,169	$ 2,678,360	$ 3,273,551	$ 3,868,742	$ 4,463,933	$ 5,059,124	$ 5,654,315

e **Incremental capital Costs**

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Adjustment factor (transformer life) [2]	50%	45%	40%	35%	30%	25%	20%	15%	10%	5%
Incremental Costs	$ 182,656	$ 164,391	$ 146,125	$ 127,859	$ 109,594	$ 91,328	$ 73,063	$ 54,797	$ 36,531	$ 18,266

f **Convert Incremental Capital Costs into Revenue Requirements**

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
2016 vintage →	18,996	18,996	18,996	18,996	18,996	18,996	18,996	18,996	18,996	18,996
2017 vintage →		17,097	17,097	17,097	17,097	17,097	17,097	17,097	17,097	17,097
2018 vintage →			15,197	15,197	15,197	15,197	15,197	15,197	15,197	15,197
2019 vintage →				13,297	13,297	13,297	13,297	13,297	13,297	13,297
2020 vintage →					11,398	11,398	11,398	11,398	11,398	11,398
2021 vintage →						9,498	9,498	9,498	9,498	9,498
2022 vintage →							7,599	7,599	7,599	7,599
2023 vintage →								5,699	5,699	5,699
2024 vintage →									3,799	3,799
2025 vintage →										1,900
Revenue Requirements →	18,996	36,093	51,290	64,587	75,985	85,483	93,082	98,781	102,580	104,479

g **Net Benefits (Total Benefits less Costs -Revenue Requirements**

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Net Benefits	$ 278,599	$ 856,694	$ 1,436,688	$ 2,018,581	$ 2,602,375	$ 3,188,067	$ 3,775,660	$ 4,365,152	$ 4,956,544	$ 5,549,835
Net benefits ($000)	$ 279	$ 857	$ 1,437	$ 2,019	$ 2,602	$ 3,188	$ 3,776	$ 4,365	$ 4,957	$ 5,550

[1] Overloaded transformers are assumed to fail within the 10 year period

[2] Remaining life for the overloaded transformers

[3] The Company inadvertently applied an incorrect carrying charge. The correct carrying charge should be 9.90%. If the Company had used the correct carrying charge (9.90%) the benefit would have been higher ($26 thousand on a cumulative basis and $17 thousand on a present value basis). The impact on the benefit to cost ratio is immaterial and hence no changes were made.

OPR 16 **Clean up Transformer leaks**

1 **Input Assumptions**

a	Total number of Spill Events (Three years)	35
b	Spills Cost per Event:	$ 2,961

2 **Intermediate Calculation**

a	Cost of Clean-up (3 years)	$ 103,635	→ Input Assumption "1a" X Input Assumption "1b"
b	Cost of Clean-up/year	$ 34,545	→ Intermediate Calculation "2a"/3

Adjusted Benefits/year

Annual Unadjusted benefit $ 34,545 Intermediate Calculation "b"

									Outside the evaluation period	
Benefit Spread over years	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Failed Transformer Proportion [1]	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
2016	$ 3,455	$ 3,455	$ 3,455	$ 3,455	$ 3,455	$ 3,455	$ 3,455	$ 3,455	$ 3,455	$ 3,455
2017		$ 6,909	$ 3,455	$ 3,455	$ 3,455	$ 3,455	$ 3,455	$ 3,455	$ 3,455	$ 3,455
2018			$ 10,364	$ 3,455	$ 3,455	$ 3,455	$ 3,455	$ 3,455	$ 3,455	$ 3,455
2019				$ 13,818	$ 3,455	$ 3,455	$ 3,455	$ 3,455	$ 3,455	$ 3,455
2020					$ 17,273	$ 3,455	$ 3,455	$ 3,455	$ 3,455	$ 3,455
2021						$ 20,727	$ 3,455	$ 3,455	$ 3,455	$ 3,455
2022							$ 24,182	$ 3,455	$ 3,455	$ 3,455
2023								$ 27,636	$ 3,455	$ 3,455
Total Benefits	$ 3,455	$ 10,364	$ 17,273	$ 24,182	$ 31,091	$ 38,000	$ 44,909	$ 51,818	$ 27,636	$ 27,636
Total Benefits in $ 000	$ 3.45	$ 10.36	$ 17.27	$ 24.18	$ 31.09	$ 38.00	$ 44.91	$ 51.82	$ 27.64	$ 27.64

[1] Overloaded transformers are assumed to fail within the 10 year period

OPR 17 **Avoided Truck rolls - Transformer Complaints**

Benefit Type: **Avoided Costs**

Input Assumptions

1	**Annual number of transformers replaced**	350	
2	**Trouble Crew Truck Rolls in Response to an Outage**		
a	Number of avoided outages across priority feeders:	429	
b	Total number of transformers across priority feeders:	9,696	
c	Total number of transformers across Pepco MD:	86,768	
d	Crew Hours avoided per event:	1.5	
e	Trouble Crew ATP:	$ 91	
3	**Truck Rolls in Response to follow-up load studies (2013 Data)**		
a	Number of follow-up referrals for OH transformers	53	
b	Total charges for OH transformer load studies	89,164	
c	Number of follow-up referrals for UG transformers	35	
d	Total charges for UG transformer load studies	76,222	

Intermediate Calculation

1	**Trouble Crew Truck Rolls in Response to an Outage**		
a	Number of avoided outages across Pepco MD:	3,839	→ (Input Assumption "2c"/Input Assumption"2b")*Input Assumption"2a"
b	Total Savings in avoiding trouble crew truck rolls:	$ 524,024	→ Intermediate Calculation "1a"*Input Assump. "2d"* Input assump. "2e"
c	Savings in avoiding trouble crew truck rolls per transformer:	$ 137	→ "*Input Assump. "2d"* Input assump. "2e"
d	Annual unadjusted benefit	$ 47,775	→ Intermediate Calculation "1c"*Input Assump. "1"
2	**Truck Rolls in Response to follow-up load studies (2013 Data)**		
a	Average cost per OH transformer follow-up load study	$ 1,682	→ Input assump. "3b"/Input Assump. "3a"
b	Average cost per OH transformer follow-up load study	$ 2,178	→ Input assump. "3d"/Input Assump. "3c"
c	Weighted Average Cost per transformer follow-up load study	$ 1,879	→ (Input Assump. "3b"+ Input Assumption "3d")/(Input Assump. "3a" +Input Assump. "3c")
d	Annual truck roll cost for follow-up load study visits (unadjusted)	$ 165,386	→ Input assump. "3b"+Input Assump. "3d"

Adjusted Benefits

1 **Trouble Crew Truck Rolls in Response to an Outage**

Annual unadjusted benefit $ 47,775 → Intermediate Cal. "1d"

									Outside the evaluation period			
Benefit Spread over years	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025		
Failed Transformer Proportion [1]	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%		
2016	$ 4,778	$ 4,778	$ 4,778	$ 4,778	$ 4,778	$ 4,778	$ 4,778	$ 4,778	$ 4,778	$ 4,778	64	$ 2,240
2017		$ 9,555	$ 4,778	$ 4,778	$ 4,778	$ 4,778	$ 4,778	$ 4,778	$ 4,778	$ 4,778		$ 280
2018			$ 14,333	$ 4,778	$ 4,778	$ 4,778	$ 4,778	$ 4,778	$ 4,778	$ 4,778		
2019				$ 19,110	$ 4,778	$ 4,778	$ 4,778	$ 4,778	$ 4,778	$ 4,778		
2020					$ 23,888	$ 4,778	$ 4,778	$ 4,778	$ 4,778	$ 4,778		
2021						$ 28,665	$ 4,778	$ 4,778	$ 4,778	$ 4,778		
2022							$ 33,443	$ 4,778	$ 4,778	$ 4,778		
2023								$ 38,220	$ 4,778	$ 4,778		
Total	$ 4,778	$ 14,333	$ 23,888	$ 33,443	$ 42,998	$ 52,553	$ 62,108	$ 71,663	$ 38,220	$ 38,220		

2 **Truck Rolls in Response to follow-up load studies (2013 Data)** 8 280
15 525

Annual Raw Benefit $ 165,386 → Intermediate Cal. "2d"

Benefit Spread over years	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Failed Transformer Proportion [1]	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
2016	$ 16,539	$ 16,539	$ 16,539	$ 16,539	$ 16,539	$ 16,539	$ 16,539	$ 16,539	$ 16,539	$ 16,539
2017		$ 33,077	$ 16,539	$ 16,539	$ 16,539	$ 16,539	$ 16,539	$ 16,539	$ 16,539	$ 16,539
2018			$ 49,616	$ 16,539	$ 16,539	$ 16,539	$ 16,539	$ 16,539	$ 16,539	$ 16,539
2019				$ 66,154	$ 16,539	$ 16,539	$ 16,539	$ 16,539	$ 16,539	$ 16,539
2020					$ 82,693	$ 16,539	$ 16,539	$ 16,539	$ 16,539	$ 16,539
2021						$ 99,232	$ 16,539	$ 16,539	$ 16,539	$ 16,539
2022							$ 115,770	$ 16,539	$ 16,539	$ 16,539
2023								$ 132,309	$ 16,539	$ 16,539
Total	$ 16,539	$ 49,616	$ 82,693	$ 115,770	$ 148,847	$ 181,925	$ 215,002	$ 248,079	$ 132,309	$ 132,309

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
3 Total Benefits	$ 21,316	$ 63,948	$ 106,581	$ 149,213	$ 191,845	$ 234,477	$ 277,109	$ 319,742	$ 170,529	$ 170,529
4 **Total Benefits ($ 000)**	**$ 21.32**	**$ 63.95**	**$ 106.58**	**$ 149.21**	**$ 191.84**	**$ 234.48**	**$ 277.11**	**$ 319.74**	$ 170.53	$ 170.53

[1] Overloaded transformers are assumed to fail within the 10 year period

Case No. 9418 - In the Matter of the Application of Potomac Electric Power Company for Adjustments to its Retail Rates for the Distribution of Electric Supply

OPC Data Request No. 2 to Staff
Request Date: July 22, 2016

Staff Response to Pepco DR No. 14 to Staff
Response Date: August 2, 2016

1. Referring to Mr. Hurley's discussion on energy market revenues, and specifically "Staff altered future energy savings for dynamic pricing events by more closely aligning savings achieved in 2015 to future expected savings. Staff also reduced savings by 10 percent in accordance with Commission Order No. 87591 in Case 9406" (p. 29), please address the following questions:
   a. Please state whether this discussion refers to OPR 19, or some other benefit(s), and if so, which ones.
   b. Please clarify how savings have been adjusted to more closely represent those achieved in 2015.
   c. Please clarify which savings Staff reduced by 10%.
   d. Please confirm the present value for OPR 19.

STAFF RESPONSE:

A. For the purpose of this analysis, Mr. Hurley calculated OPR 19 out to 2023 based on the U.S. Supreme Court Decision that energy reductions from demand response programs are eligible to receive PJM energy market revenues. This value combines the benefit categories OPR 19 and DSM 9. Mr. Hurley did not include a value for DSM in his testimony.
B. Please see Attachment 1an excel spreadsheet titled, Benefits Worksheet Att C Staff Core.xls, specifically the workbook Dynamic Pricing Benefits_1, Rows F:20 to N:20 and G:21 to N:21.
C. See response to OPC data request 2-1.B
D. The present value for OPR 19 is $731,000.

SPONSOR: Daniel Hurley

Case No. 9418 - In the Matter of the Application of Potomac Electric Power Company for Adjustments to its Retail Rates for the Distribution of Electric Supply

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2. Given that PEPCo only identifies $56,000 (Hurley, p. 19), please explain how Hurley calculates a present value of $731,000 for OPR 19–Energy price Earnings (p. 29).
   a. If this result is an error, please the correct value.
   b. Please provide the derivation of the correct value.

STAFF RESPONSE:

A. The result is not in error.
B. Please see Staff's Response to OPC Data Request 2-1, Parts A and B.

SPONSOR: Daniel Hurley

Case No. 9418 - In the Matter of the Application of Potomac Electric Power Company for Adjustments to its Retail Rates for the Distribution of Electric Supply

OPC Data Request No. 2 to Staff
Request Date: July 22, 2016

Staff Response to Pepco DR No. 14 to Staff
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3. Referring to Mr. Hurley's testimony on page 28, when asked what present value of energy-price earning is estimated by the company, Mr. Hurley responds 'The present value of *capacity* revenue [is] $1.5 million."
   a. Please explain how the capacity revenue referred to is related to PJM energy price earnings estimated by Pepco.
   b. Please identify the benefit IDs included in the $1.5 million energy price earnings Mr. Hurley indicates have been estimated by Pepco (p.29).
   c. If Mr. Hurley intended a different answer please clarify the response.

STAFF RESPONSE:

A. This is a typographical error on Mr. Hurley's testimony. The answer on page 28 should have said, "The Company estimated the present value of energy savings at $1.5 million.
B. Mr. Hurley combined benefit categories OPR 19 and DSM 9 to calculate this value.
C. N/A

SPONSOR: Daniel Hurley

Case No. 9418 - In the Matter of the Application of Potomac Electric Power Company for Adjustments to its Retail Rates for the Distribution of Electric Supply

OPC Data Request No. 2 to Staff
Request Date: July 22, 2016

Staff Response to Pepco DR No. 14 to Staff
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4. Referring to capacity price mitigation assumptions:
   a. Does Mr. Hurley agree that Pepco assumes each 1 MW demand reduction will result in a corresponding 1 MW decline in forecast PJM peak load and capacity requirement?
   b. Does Mr. Hurley believe that each 1MW demand reduction at peak results in a 1MW reduction of PJM's forecast peak load and a proportionate reduction in capacity requirement?
      i) If so, please provide the basis for this belief.
   c. If PJM scenario analysis estimates that a 1MW reduction in Pepco load would result in a reduction of less than one MW in PJM's estimate of forecast system load, would Mr. Hurley accept these PJM results for the purpose of estimate capacity price mitigation?

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STAFF RESPONSE:

A. Mr. Hurley's calculation for Capacity Price Mitigation only included MW reductions cleared in a completed PJM Base Residual Action and only included mitigation effects on the supply side of the market. Mr. Hurley used the accepted VRR methodology approved by the Commission in Order Nos. 87802, 87213 and 87591. As discussed in his direct testimony, Mr. Hurley noted the uncertainty in how PJM will adjust its load forecast in response to demand reductions caused by demand side management type programs and recommended the Commission to require Pepco to file a similar report to the one the Commission required BGE to file on how the Company intends to address this issue with PJM to bring about necessary adjustments to PJME forecasts in the future.
B. See response to OPC data request 2-4.A.
C. See response to OPC data request 2-4.A.

SPONSOR: Daniel Hurley