EXHIBIT NO. _____ (AML-13T)
DOCKET NOS. UE-170033/UG-170034
2017 PSE GENERAL RATE CASE
WITNESS: AMANDA M. LEVIN

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITES AND TRANSPORTATION COMMISSION, Complainant, v. PUGET SOUND ENERGY, Respondent.	DOCKET NOS. UE-170033 and UG-170034 (*Consolidated)*

EXHIBIT AML-16 TO THE

CROSS-ANSWERING TESTIMONY (NON-CONFIDENTIAL) OF

AMANDA M. LEVIN

ON BEHALF OF NORTHWEST ENERGY COALITION, RENEWABLE NORTHWEST,

AND NATURAL RESOURCES DEFENSE COUNCIL

NON-CONFIDENTIAL

August 9, 2017

BEFORE
THE PUBLIC UTILITIES COMMISSION OF OHIO

In the Matter of the Application of Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to R.C. 4928.143, in the Form of an Electric Security Plan.	**)))))**	**Case No. 16-1852-EL-SSO**
In the Matter of the Application of Ohio Power Company for Approval of Certain Accounting Authority.	**)))**	**Case No. 16-1853-EL-AAM**

DIRECT TESTIMONY OF

PAUL CHERNICK

ON BEHALF OF

NATURAL RESOURCES DEFENSE COUNCIL

Resource Insight, Inc.

MAY 2, 2017

TABLE OF CONTENTS

Exhibits

I. IDENTIFICATION & QUALIFICATIONS

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

A: My name is 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 a Bachelor of Science degree from the Massachusetts Institute of Technology in June 1974 from the Civil Engineering Department, and a Master of Science degree from the Massachusetts Institute of Technology in February 1978 in technology and policy.

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 U.S. 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 Public Utilities Commission of Ohio (the "Commission")?

A: Yes. I have testified five times before the Commission:

- In Cases No. 91-635-EL-FOR, 92-312-EL-FOR, 92-1172-EL-ECP, on behalf of the City of Cincinnati on the treatment of demand-side management (DSM) in the Cincinnati Gas and Electric Long Term Forecast Report for 1992.
- In Case No. 95-203-EL-FOR, on behalf of the Campaign for an Energy Efficient Ohio on cost-effectiveness tests for electric DSM.
- In Case 03-2144-EL-ATA, on behalf of Green Mountain Energy on the pricing of standard-offer service.
- In Case No. 05-1444-GA-UNC, on behalf of the Ohio Consumers' Counsel (OCC) on energy-efficiency analysis and planning.
- In Case No. 14-1693-EL-RDR, on behalf of Sierra Club, on AEP Ohio's proposed affiliate power purchase agreement.

I have also advised and assisted the Ohio Consumers' Counsel and other parties on a number of issues related to various Ohio utilities.

II. INTRODUCTION

Q: On whose behalf are you testifying?

A: I am testifying on behalf of the Natural Resources Defense Council.

Q: What is the scope of your testimony?

A: I evaluate and respond to the rate design component of Ohio Power Company's ("AEP Ohio" or the "Company") amended electric security plan (the "Amended ESP") that will modify the current ESP III and extend its term through May 2024. While the Amended ESP includes a number of issues, I confine my testimony to the Company's proposal to restructure its residential rates. Specifically, the Company proposes to increase the base residential customer charge by a total of $10 over two phases: initially from the current $8.40 per month to $13.40 per month, with a subsequent increase to $18.40 per month on January 1, 2018. The Company also proposes a corresponding reduction in the distribution energy charge for residential customers of about 0.97¢/kWh by 2018.

AEP Ohio's proposal would more than double the base customer charge (a 119% increase from the current level) effective January 1, 2018, and decrease the distribution energy charge by more than half (53%).

Q: Please briefly summarize your conclusions regarding the Company's proposal.

A: It would inappropriately shift recovery of usage-related costs from the energy charge to the customer charge, unreasonably dampen energy price signals, discourage conservation by residential customers, and increase energy consumption. It would also unjustly result in subsidization of high-usage customers by low-usage customers and increase monthly bills for the vast majority of AEP Ohio's residential customers. For these reasons, the customer charge should not be increased in this proceeding.

Q: What information did you review in preparing this testimony?

A: I reviewed the Amended ESP, relevant prefiled testimony of Company witnesses, filed Company schedules and tables, and relevant Company responses to information requests. I also reviewed, among other things, material from AEP Ohio's filings in 11-351-EL-AIR, and Ohio Revised Code ("ORC") §4928.02.

Q: How is your testimony organized?

A: The remaining sections cover the following topics:

- In Section III, I provide a high level summary of AEP Ohio's proposal and my concerns with the Company's rationale and the impacts the customer charge increase will likely have on customers and their energy choices;
- In Section IV, I discuss the industry-standard principles that are commonly applied when evaluating rate design changes, as well as relevant Ohio energy policies that should be taken into account;
- In Section V, I introduce the basics of designing cost-based rates relevant to AEP Ohio's proposal, including a discussion of the costs that are most appropriate to include in the customer charge and energy charge. Further, I analyze the proposed customer charge increase from a cost-causation standpoint and conclude that it would result in inappropriate and unnecessary cost shifts;
- In Section VI, I lay out the bill impacts and likely effects on energy use and conservation that would occur if the Company's proposal were implemented;
- In Section VII, I address AEP Ohio's other claims with regard to its rate design proposal, including the assertion that a higher customer charge would be helpful in moderating bill volatility. In addition, I address the fact

that AEP Ohio appears to know very little about its low-income customers (particularly those who use less than the average amount of energy), and has not addressed the regressiveness of its proposal for those customers and other vulnerable Ohioans;

- In Section VIII, I discuss AEP Ohio's revenue decoupling mechanism.
- In Section IX, I address my concern with the Company's apparent preference for residential demand charges; and
- Finally, in Section X, I summarize my recommendations.

III. SUMMARY OF CONCERNS WITH RATE DESIGN PROPOSAL

Q: Why do AEP Ohio's proposed changes in rate design matter?

A: As I describe more fully throughout my testimony, the customer charge is static and does not change from month to month, regardless of how much—or how little—energy a customer uses. Thus, this charge cannot be lowered by customer efforts to conserve energy, whether through energy efficiency investment, home automation, greater care in energy use, or installation of distributed energy resources such as rooftop solar. The increased customer charge results in reductions in energy charges, sending inefficient price signals to customers that tend to reward increased consumption.

In addition to these concerns, increasing the customer charge inappropriately shifts distribution costs onto customers with below-average energy use. Shifting such costs onto customers who do not cause them reduces the equity of the rate structure.

Q: Does AEP Ohio's proposed $18.40 customer charge represent the total charge that residential customers will pay?

A: No. It is important to take into account the numerous riders that AEP Ohio adds to the customer charge. A range of current riders add about 43.3% to the base customer charge, plus an additional $1.01 per month from the gridSMART Phase 1 Rider.[1] Taking into account these existing riders, the current effective customer charge is already $13.05 per month—nearly $5 above the stated base charge of $8.40.[2] Thus, if the base customer charge proposed by AEP Ohio were implemented in full (including all riders), residential customers would effectively be paying $27.40 per month in a static, unchangeable charge as of January 1, 2018.[3]

Further, these riders increase over time. Workpapers filed by AEP Ohio witness David Gill document an effective customer charge of $29.71 by June 2018, including percentage adders totaling 52.6%, with similar increases in subsequent years.[4]

Q: What is AEP Ohio's rationale for proposing such dramatic changes in its residential rate design?

A: The increase in the customer charge is proposed in the testimony of AEP Ohio witness Andrea Moore (at 12–14). Her rationale includes three parts. First, she asserts that:

---

[1] The riders that are computed as a percentage of base rate charges are the Residential Distribution Credit (–3.6%), Deferred Asset Phase-In (7.7%), Economic Development Cost Recovery (1.1%), Enhanced Service Reliability (7.3%) and Distribution Investment (29.0%). Those adders are also shown in the Bill Calculation Spreadsheets on the Company web site (www.AEPohio.com/account/bills/rates/AEPOhioRatesTariffsOH.aspx). Similar, but slightly different, values are shown in hidden columns in the spreadsheet form of AEP Ohio witness David Gill's Workpaper DRG-7, in the "SSO Impacts" tabs.

[2] Current residential base customer charge [$8.40] + ($8.40 × percentage rider increase [0.433]) + gridSMART Phase 1 Rider [$1.01] = $13.05/month.

[3] Proposed residential base customer charge [$18.40] + ($18.40 × percentage rider increase [0.433]) + gridSMART Phase 1 Rider [$1.01] = $27.40/month.

[4] *See* David Gill spreadsheet workpaper for Exhibit DRG-7 (typical Bill impacts DRG-7.xlsx). Mr. Gill documents an effective total charge for a customer with zero consumption to be $29.71 in June 2018, rising to $32.18 in 2019, $33.68 in 2020, and $34.92 in 2021.

> The Company filed, in Case No. 11-351-EL-AIR, an updated cost of service study showing that a full customer charge should be $27.24 for a standard residential customer. While it is appropriate to move customers towards the full customer charge, the Company is proposing to implement this charge in a gradual fashion.
>
> Distribution costs are incurred by sizing the distribution system to meet customer(s) peak kW demand usage. These costs vary by peak demand requirements, not by kWh usage or by simply connecting a customer to the system These costs would ideally be collected through a demand charge, but this cannot be done for all customers due to the current limitations of the Company's metering infrastructure.[5]

Second, she observes that "by removing a portion of the fixed costs from the energy charge, some customers will see less volatility in bills from high usage months, especially customers who use electric heat."[6]

Third, Ms. Moore asserts that:

> Another benefit from this design is that Percentage of Income Payment Plan customers in 2014 and 2015 have used on average slightly over the break even kWh for the customer charge of 1,030 kilowatt hours. This proposal will lower the PIPP bills, therefore lowering the future revenue requirement of the Universal Service Fund.[7]

Q: What is your opinion of AEP Ohio's proposed increase in the residential customer charge?

A: The Company's proposal is not in the public interest, as it would yield a rate design that is inequitable, inefficient, and regressive, in contravention of a host of long-standing ratemaking principles and Ohio energy policy. What limited rationale AEP Ohio offers is inadequate and at times misleading, particularly given the significant impacts of the proposal on customers.

[5] Moore Direct at 13.

[6] *Id.*

[7] *Id.*

While I describe these issues in detail in later portions of this testimony, the following is a brief summary of my main concerns:

- As discussed in Section V, AEP Ohio's proposal would inappropriately shift costs from high-use customers to those who use less than the average energy—without sufficient cost basis. The proposed $18.40 per month customer charge is much higher than the costs that should appropriately be collected through this charge. The customer charge should include only those costs of connecting an additional customer to the distribution system. That value is likely already close to (if a bit less than) the current base customer charge of $8.40 per month. Thus, no increase is warranted.
- As discussed in Section VI, the proposed rate design restructuring would have a number of detrimental impacts on customers. It would increase monthly bills for about 65% of the residential class. Further, it would impact clean energy efforts in contravention of state policy, by decreasing the ability and incentives for customers to manage their electric bills, through energy conservation. Unfortunately the Company has taken little to no steps to address these impacts, particularly for low-income or other at-risk customers. Further, as discussed in Section VII, the Company knows precious little about its low-income customers, save for the limited cross-section of Ohioans that participate in the PIPP program. And while the Company offers that some of these customers may experience less volatility in bills with a customer charge increase, this is of dubious benefit given the equity and clean energy impacts of the proposal.
- As discussed in Section VIII, no customer charge increase is necessary to stabilize AEP Ohio's revenues, since the Company already has a

decoupling rider in place, in the Pilot Throughput Balancing Adjustment Rider (the "PTBAR"). The PTBAR ensures that the Company collects the Commission-authorized revenue requirement annually and—in contrast to a customer-charge increase—maintains the price signal for customers to conserve energy.

- Finally, as discussed in Section IX, AEP Ohio appears to be creating the narrative for a future rate design in which demand-relateda portion of residential distribution costs would be collected through a residential demand charge. Demand charges for the residential class are untested and should be viewed with caution. They do not charge residential customers for their usage at the times that contribute to the costs of the distribution system, and do not provide useful incentives for customers to reduce the burdens they impose on the system.

IV. THE GOALS OF RATE DESIGN

A. Standard Ratemaking Principles

Q: Please describe some of the principles that are usually referenced in designing rates.

A: An industry standard reference for ratemaking concepts, *Principles of Public Utility Rates* by James C. Bonbright (1961, at 291), lists the following criteria for a "desirable rate structure," a term that Bonbright uses broadly to describe rate design, revenue allocation, and some aspects of setting the revenue requirement:[8]

[8] The entire 1961 version of *Principles of Public Utility Rates* is available at: media.terry.uga.edu/documents/exec_ed/bonbright/principles_of_public_utility_rates.pdf

1. The related, "practical" attributes of simplicity, understandability, public acceptability, and feasibility of application.
2. Freedom from controversies as to proper interpretation.
3. Effectiveness in yielding total revenue requirements under the fair-return standard.
4. Revenue stability from year to year.
5. Stability of the rates themselves, with a minimum of unexpected changes seriously adverse to existing customers.
6. Fairness of the specific rates in the apportionment of total costs of service among the different consumers.
7. Avoidance of "undue discrimination" in rate relationships.
8. Efficiency of the rate classes and rate blocks in discouraging wasteful use of service while promoting all justified types and amounts of use:
   a) in the control of the total amounts of service supplied by the company:
   b) in the control of the relative uses of alternative types of service (on-peak versus off-peak electricity…).

Q: How do these Bonbright criteria apply to the rate design issues in this case?

A: Criteria 1 and 2—simplicity and clarity—are important, but tend to be non-controversial: rate designs should be understood by customers and easy to administer. As I discuss in Section IX**Error! Reference source not found.** of this testimony, the potential application of demand charges to small customers is an example of a rate design that would create challenges for customer understanding.

Criteria 3 and 4—revenue adequacy and stability—concern the determination of the revenue requirement and updating that requirement to reflect changes in costs and sales. For AEP Ohio, a variety of adjustments allow the Company to recover its authorized revenue requirement between rate proceedings, including the existing PTBAR and reconciling adders.

Criterion 5—rate stability or gradualism—is satisfied by any rate design that does not change abruptly. AEP Ohio's proposal to more than double the residential customer charge by January 1, 2018 would violate this principle.[9]

Criteria 6 and 7 require that the allocation of revenue requirements among classes be "fair" and avoid "undue discrimination." The resulting standard is far from a requirement of precise revenue allocation, since "fair" and "undue" are subjective terms. These criteria can also be read as applying those standards to the rate design that spreads costs among customers within a rate class. Because AEP Ohio's proposal would shift costs incurred by and for higher-use customers to low-use customers (as I discuss in Section VI.A), it does not meet this fairness criterion.

Criterion 8 focuses the rate-design process on providing efficient price signals. AEP Ohio's proposal to offset the increase in the customer charge by reducing the energy charge would create inefficient price signals and thus would not meet this standard (as I discuss in Section VI.B).

Table 1 summarizes the Bonbright criteria and their application to AEP Ohio's proposal and residential rate design more generally.

[9] Specifically, regulators usually require gradualism in changes to rate design and cost allocation, spreading large increases over many years.

Table 1: Rate-Design Implications of Bonbright Criteria

Criterion	Implications for AEP Ohio Rate Design
1 Simple, understandable, acceptable, feasible	Avoid demand charges Explain any new rate designs clearly
2 Clarity	
3 Revenue level	Decoupling resolves these issues
4 Revenue stability	
5 Rate stability	Avoid abrupt changes in rate design, gradualism
6 Fairness	Charge customers for the costs caused by their use (e.g., low-use customers do not subsidize high use)
7 No undue discrimination	Keep charges simple and consistent
8 Efficiency	Recover distribution costs in proportion to a customer's usage of the system, ideally by time varying rates

B. Relevant Ohio Policies

Q: What state energy policies are relevant to the Commission's review of AEP Ohio's rate-design proposal?

A: Ohio state energy policy is reflected in ORC §4928.02. Relevant to this proceeding, it provides for the following:

- ORC §4928.02(C) Ensure diversity of electricity supplies and suppliers, by giving consumers effective choices over the selection of those supplies and suppliers and by encouraging the development of distributed and small generation facilities;
- ORC §4928.02(D) Encourage innovation and market access for cost-effective supply- and demand-side retail electric service including, but not limited to, demand-side management, time-differentiated pricing, waste energy recovery systems, smart grid programs, and implementation of advanced metering infrastructure;
- ORC §4928.02(L) Protect at-risk populations, including, but not limited to, when considering the implementation of any new advanced energy or renewable energy resource.

Q: Would AEP Ohio's proposal be consistent with these provisions?

A: No, as I discuss in Section VI, AEP Ohio's proposal is unreasonably burdensome and inequitable for the vast majority of residential customers. To the extent a portion of those customers are low-income, that burden would be heavily weighted towards at-risk populations. Further, the proposal yields inefficient price signals that will discourage customers from making clean energy choices—both in reducing their energy use and in making distributed generation decisions— in contravention of Ohio energy policy.

V. DESIGNING COST-BASED RATES

Q: How is this section organized?

A: In the following sections, I break down the standard steps in setting cost-based rates, including the formulation of customer and energy charges, and make recommendations regarding the Commission's consideration of those charges for AEP Ohio's residential customers. Understanding this framework and how it relates to the rates that customers pay is important, since AEP Ohio is proposing to shift substantial residential distribution cost recovery from the energy charge to the customer charge.

A. Fundamentals of Rate Design

Q: What are the relevant considerations in designing residential electric rates?

A: Residential electric rate design usually includes only a customer charge and one or more energy charges.[10] As discussed in more detail below, the

[10] The energy charge may vary with usage (e.g., in an inclining-block rate, in which price rises with usage level), with season, and (where the customers have the necessary metering installed) with time of day. AEP Ohio has not proposed any differentiation of the energy charge or provided the data necessary for time variation, so I will assume in this discussion that there will be only one energy charge.

customer charge should reflect some measure of the cost of serving an additional customer, the cost saved by reducing the number of customers, or a fair share of the costs that result from the number of customers served, independent of the amount of energy they use.

In contrast, the energy charge should reflect the costs that vary with the amount of power delivered, independent of the number of customers served. For an electric distribution utility, such as AEP Ohio, the costs of delivering power are the costs of building and maintaining the distribution system.

Q: What is the most straightforward approach to calculating residential customer and energy charges?

A: The simplest cost-based approach to determining the cost categories that could appropriately be collected through the customer and energy charges consists of the following steps:

- Add up the embedded revenue requirements attributable to the number of customers and divide by the number of annual residential bills to derive a customer charge in $/customer-month.
- Add up the remainder of the revenue requirements and divide by the residential energy sales, to derive an energy change in ¢/kWh.

Embedded costs are generally used to allocate costs among rate classes, as AEP Ohio did in the cost-of-service study in its 2011 rate case, Case No. 11-351-EL-AIR, part of which is reproduced in Exhibit PLC-3.

Variants on this approach reflect marginal costs: the cost of adding a customer, the benefit of removing a customer, or the cost of reinforcing the system to accommodate increased energy growth. Computing marginal customer cost and marginal distribution energy cost is a significant incremental effort, which neither AEP Ohio nor I have undertaken in this case.

Once cost-based customer and energy charges are calculated, the next step is to apply Bonbright's rate design principles and relevant state energy policies. I discuss the application of these principles in the context of the impact of AEP Ohio's proposal on customers and conservation in Section VI.

B. AEP's Ohio's Overall Distribution Costs

Q: What costs are recovered through AEP Ohio's distribution rates?

A: A utility distribution system generally consists of the following major classes of equipment costs:

- Substations are primarily large transformers that step down transmission voltages (such as 69 kV and 138 kV) to the distribution voltages of 2,400 V to 34,500 V.[11]
- Feeders, or primary lines, typically serve hundreds or thousands of customers, running miles from the distribution substation to the locations of primary-voltage customers and the line transformers serving secondary-voltage customers.
- The line transformers (usually cylinders on poles or rectangular boxes mounted on concrete pads) step the primary voltage down to voltages that can be used by residential and most other customers, which range from 120 V to 480 V.

---

[11] These voltage levels are listed in the AEP Ohio Standard Tariff, posted at www.aepohio.com/global/utilities/lib/docs/ratesandtariffs/Ohio/2017-04-28_AEP_Ohio_Standard_Tariff.pdf

- From the line transformers, power flows directly to some customers over service drops, and runs along the street (or other public way) on secondary lines, to the service drops of other customers.
- The service drops, whether fed directly from the line transformer or through secondary lines, run either overhead or underground from the street to the customer's home or other building. In the case of a multifamily building, there will usually be one service drop to the building.
- Power runs from the service drop through customer-owned wires to the meter, and then on to the customer's circuit breakers.

The costs of the distribution system consists of: 1) the interest, return, taxes and depreciation associated with the capital investments; 2) operating and maintenance (O&M) expenses; and 3) allocations of overhead and general costs. The customer-related costs comprise the service drops, meters, and expenses for maintaining that equipment; as well as the costs of meter reading, billing, and otherwise dealing with customers. These costs are called "customer accounts" and "customer service" costs in the FERC accounting system.

C. Setting the Customer Charge

Q: What distribution system costs should be attributed to the customer charge?

A: The primary challenge in rate design is to reflect the costs that customers impose, both to encourage them to use utility resources responsibly and to share costs fairly. The customer charge is intended to reflect the incremental costs imposed by the continued presence of a customer who uses very little energy. Thus, the customer charge should not be expected to cover all customer-related costs for the average residential customer, but only the incremental cost to connect one more very small customer.[12] Since AEP Ohio would probably not need to add any secondary conductor or a transformer to connect most of its very small customers (who would tend to be in apartment buildings), incremental connection costs would be limited to installation and maintenance costs for a service drop and meter, along with meter-reading, billing, and other customer-service expenses.[13]

Further, given the narrow categories of costs that should be recovered through the customer charge, the only useful price signals that a customer charge provides are related to consumer decisions regarding whether to have the Company install a meter (and whatever other equipment is necessary) and whether to have AEP Ohio continue metering and billing a location where the energy delivered is of very little value.

Q: Should customer charges be based on average or incremental costs?

A: While a number of considerations affect the choice of an appropriate customer charge, the incremental costs—i.e. the costs of connecting an additional customer to the distribution system—are the important costs for giving customers signals regarding the cost of keeping them connected to the system.

The average embedded customer-related cost is a convenient reference value, however, even though it will usually be higher than an estimate of the

[12] *See, e.g.*, Jim Lazar & Wilson Gonzalez, Smart Rate Design for a Smart Future, Regulatory Assistance Project, 36 (July 2015), available at www.raponline.org/wp-content/uploads/2016/05/rap-lazar-gonzalez-smart-rate-design-july2015.pdf.

[13] Remote residences might also require a line extension and a small transformer in order to connect to the distribution system. On the other hand, customers located in a multi-family building would probably not require their own service drop.

incremental costs. The average embedded cost includes the costs of services, meters, meter reading, billing, collections, other customer services, and associated overheads. The billing system, the call center, and other expenses are likely to have high fixed costs (e.g., the billing computers and software), so the marginal cost of serving an additional customer is likely to be lower than the embedded cost. The smallest customers are almost certainly concentrated in apartment buildings, so adding an additional customer does not require a service drop (since the building only requires one drop) and the density of the customers reduces meter-reading costs, compared to suburban single-family homes. Small customers will also have smaller bills and will be less likely to bother contacting AEP Ohio's customer service operations.

Q: **Have either you or AEP Ohio calculated the cost of connecting an additional residential customer?**

A: No. As indicated above, calculating marginal costs is a significant effort, which neither AEP Ohio nor I have undertaken in this case.

Q: What calculation do you propose to use instead?

A: In Case No. 11-351-EL-AIR the Company calculated the average embedded costs of serving residential customers (independent of usage). The Company's Schedule E-3.1 in that proceeding, attached as Exhibit PLC-3, shows a "Full Cost Customer Charge" of \$8.47/customer-month.[14] While this value would be higher than the incremental cost of adding an additional customer, it appears to be a reasonable estimate of the average embedded

[14] This cost was calculated in 2011 dollars. Some cost components have likely increased since 2011 (due to inflation and installation of additional advanced meters), while others have probably decreased (due to depreciation, amortization and reductions in meter-reading and other costs resulting from the advanced meters). The increases are recovered to some extent in riders, and might not affect an update of the base customer charge to 2017 or 2018.

cost and is close to the current base residential customer charge of $8.40 per month.

In arriving at this figure, AEP Ohio summed the following embedded rate-base cost components:

- Services
- Meters
- General Plant and Intangible Plant
- Working Capital
- Materials and Supplies
- Pension Pre-payments

AEP Ohio subtracted rate base credits for Accumulated Depreciation, Customer Deposits and net Deferred Taxes, and computed the revenues necessary to cover the interest and equity return on the net rate base. To those costs, AEP Ohio adds depreciation and amortization of the gross plant values, as well as the following components of operations and maintenance expenses:

- Meters
- Customer Installations
- Rents
- Miscellaneous Distribution
- Meter Reading
- Customer Records & Collection
- Uncollectible Accounts
- Interest on Customer Deposits
- Miscellaneous Customer Accounts
- Supervision and Engineering for distribution and customer service
- Administrative and General Expenses

The Company then divided the total residential customer-related costs by the annual number of residential bills.

I note that this estimate of the customer-related costs is *less than a third* of the $27.24 per month value that Ms. Moore asserts should be reflected in the customer charge.

Q: What support does Ms. Moore give for the statement that "a full customer charge should be $27.24 for a standard residential customer"?[15]

A: Ms. Moore is referencing the Company's updated July 2015 cost of service study filed in Case No. 11-351-EL-AIR. This $27.24 figure represents a "Residential distribution charge of $27.24 per bill" for a "Straight Fixed-Variable rate design."[16] AEP Ohio explained in discovery responses that the $27.24 value is actually just the ratio of total residential distribution base revenues, divided by the number of customer bills.

> The $27.24 represents the average base revenue per residential bill. The residential base revenues that support the $27.24 were presented in Column K of Schedule E-4.1 in Case Nos. 11-351-EL-AIR and 11-352-EL-AIR and were calculated using base rates at the time of that filing. The total number of residential bills issued during the test period are presented in Column C of the same schedules.[17]

---

[15] Moore Direct at 13.

[16] Ex. PLC-2.

[17] Ex. PLC-4.

Q: What costs are included in the $27.24 per month that Ms. Moore says should ideally be "the full customer charge…for a standard residential customer"?

A: In contrast to AEP Ohio's 2011 estimate of $8.47 per month in average embedded customer-related costs, the $27.74 value appears to include the *entire* embedded distribution cost that AEP Ohio has allocated to the residential class, divided by the number of residential customer months. The $27.24 thus includes the costs of substations, feeders and line transformers, which are entirely or mainly driven by factors other than the number of customers. It is inappropriate to include such costs in the customer charge.

Ms. Moore presents the $27.24 value as if it were AEP Ohio's estimate of *customer-related* costs, but it is not. I see no analysis in the Company's Amended ESP filings, the 2011 rate case docket, or in discovery responses that parse out which portion of these distribution costs should appropriately be considered customer-related, and which should be considered demand-related. Rather, Ms. Moore's testimony implicitly assumes that *all* distribution costs should be recovered through a fixed customer charge in dollars per customer-month, independent of customer usage of the distribution system.

Q: Do you agree that all distribution costs should be recovered through a charge per customer-month?

A: No. Some costs are driven primarily by the number of customers, and can reasonably be collected through a charge per customer-month. Other costs are determined by various measures of load, such as peak and near-peak loads on the substations, feeders, line transformers and secondary lines. Energy requirements prior to the peak hours also contribute to the sizing of equipment, and to the rate at which equipment wears out. And some costs result from decisions to extend power lines; those decisions are usually based on projections of revenue from the load on the extended line, and are therefore due more to energy use than customer number.

Q: Has AEP Ohio provided any argument for recovering additional costs through the customer charge?

A: When asked for AEP Ohio's basis for believing that "the proposed increase more accurately reflects the cost causation from the customers' use of the distribution system," the Company responded:

> The cost of providing distribution service do not vary with volumetric usage. Generally, the distribution system costs are affected by either peak demand imposed on the distribution facilities or by the number of customers served. If these costs are primarily recovered through an energy charge, the customer is sent a price signal that by lowering their usage they are lowering the cost imposed on the system even though they have not necessarily lowered the costs imposed on the system.[18]

The same interrogatory asked AEP Ohio to "list the components of the distribution system for which the Company believes that cost causation is more accurately reflected by including the cost in a customer charge, rather than in an energy charge." The Company did not identify any such components of the distribution system.[19]

Q: Does this response justify recovering distribution costs through the customer charge?

A: No. This response is incorrect in at least three ways. First, the cost of providing distribution service really does "vary with volumetric usage." A customer who uses large volumes of electricity will impose higher costs on the system than one who uses very little power, unless they have very strange

---

[18] Ex. PLC-5.

[19] *Id.*

load shapes.[20] While a customer who increases energy use will probably—even if not *necessarily*—have raised the costs imposed on the system, we know that a customer who adds a meter without changing usage adds no costs to the distribution system. Second, while total energy consumption is an imperfect proxy for the costs imposed on the distribution system by a customer, the customer charge has no correlation with contribution to distribution costs. Third, while the price signal from a simple energy charge is imperfect, the customer charge gives customers no useful price signal regarding distribution costs.

D. Setting the Energy Charge

Q: How should residential distribution energy charges be set in order to provide appropriate price signals and encourage conservation?

A: Energy charges should be set at levels that recover costs that tend to increase with customer usage. This includes the following three high-level cost categories:

- Costs directly driven by customer usage, such as the costs of substations and the sizing and number of distribution conductors and line transformers.
- Costs driven by geographic expansion of the distribution system, which in turn is driven by anticipated consumption and revenue.
- Costs that tend to be correlated with customer usage level but are not directly caused by customer usage.

[20] The drivers of distribution costs would be best reflected by a time-of-use rate that spreads distribution costs among hours in proportion to the probability of substations, feeders, and transformers being heavily loaded. With the advanced metering that AEP Ohio has installed, identifying those hours and charging appropriate rates should not be difficult.

Q: Concerning the first category, what usage factors directly increase the costs of substations, conductors and line transformers?

A: The cost of all these components are driven by a combination of the hours with high loads on the equipment and the energy usage leading up to the high loads.

Q: How does energy consumption affect the life of distribution equipment?

A: Existing distribution equipment wears out faster if it is more heavily loaded. The capacities of transformers and underground power lines, in particular are limited by the build-up of heat created by electric energy losses in the equipment. Every time a transformer approaches or exceeds its rated capacity (a common occurrence, since transformers can typically operate above their rated capacity for short periods of time), its internal insulation deteriorates and it loses a portion of its useful life. Long hours of high loads result in heat building up in lines (especially underground lines) and transformers, increasing the damage of peak loadings.

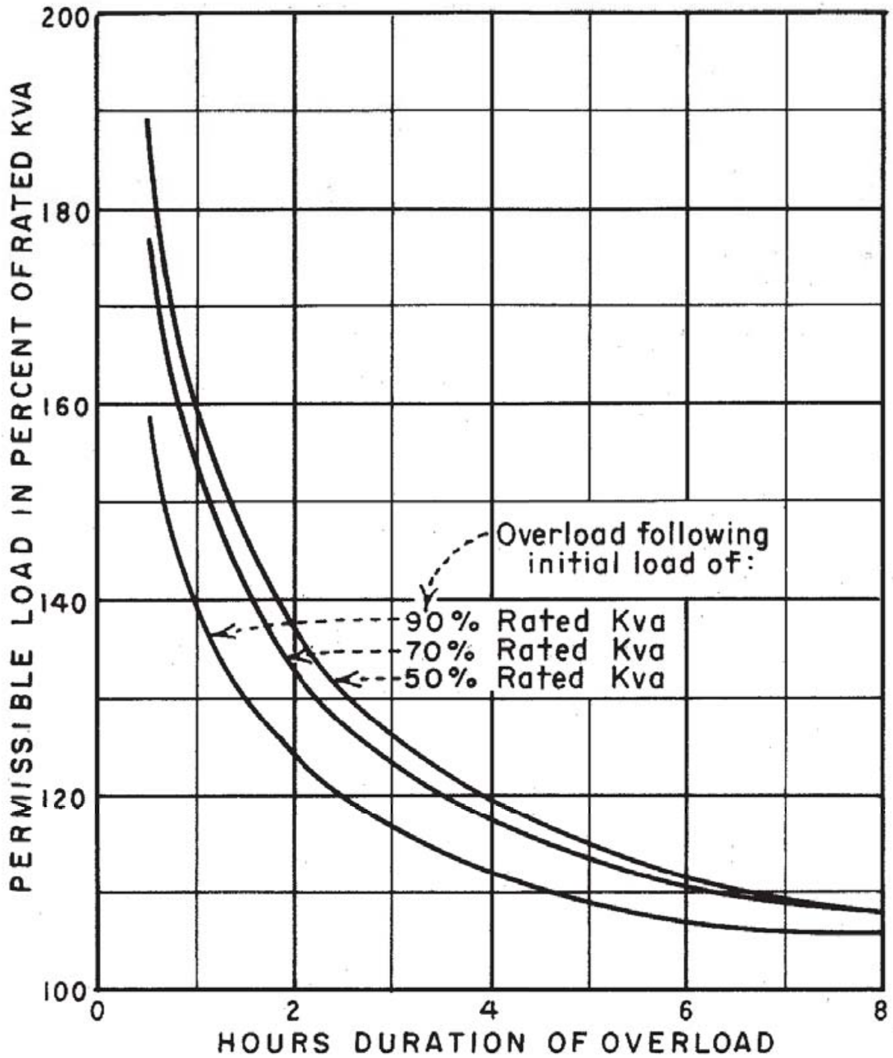
Figure 1 illustrates the effect of the length of the peak load, and the load in preceding hours, on the load that a transformer can carry without losing operating life.[21] The initial load in Figure 1 is defined as the maximum of the average load in the preceding two hours or 24 hours. A transformer that was loaded to 50% of its rating in the afternoon can endure an overload of 190% for 30 minutes or 160% for an hour. If the afternoon load was 90% of the

[21] *See Permissible Loading of Oil-Immersed Transformers and Regulators*, United States Department of the Interior, Bureau of Reclamation, Facilities Engineering Branch, Denver Office, April 1991, available at www.usbr.gov/power/data/fist/fist1_5/vol1-5.pdf . This specific example is for self-cooled and water-cooled transformers designed for a 55°C temperature rise; other designs show similar patterns.

transformer rating, it could only carry 160% of its rated load for 30 minutes or 140% for an hour.[22]

[22] Utilities recognize that the length of overloads is critical to determining whether a transformer needs to be replaced. For example, Exelon Maryland operating companies Potomac Electric Power (PEPCo) and Delmarva Power and Light have established standards for replacing line transformers when the average load over a five-hour period (determined from the reading on the advanced meters of the customers served by the transformer) exceeds 160% of the rating of overhead transformers or 100% for padmount transformers. See, e.g., testimony of Karen Lefkowitz at 41 in MD OPC Case No. 9418 (webapp.psc.state.md.us/newIntranet/Casenum/NewIndex3_VOpenFile.cfm?filepath=C:\Casenum\9400-9499\9418\Item_1\\2016PepcoMDRateCaseApplicationDirectTestimonyandExhibitsVolIofII041616.pdf) or similar testimony in MD OPC Case No. 9424 (http://webapp.psc.state.md.us/newIntranet/casenum/NewIndex3_VOpenFile.cfm?filepath=C:\Casenum\9400-9499\9424\http://www.psc.state.md.us/) These major utilities have not found it necessary to establish comparable policies for shorter periods.

Figure 1: Permissible Overload for Varying Periods



Similarly, if the transformer's high-load period is three hours in the afternoon and evening, and the preceding load is 50% of rated capacity, the permissible load would be about 127% of rated capacity, but increasing the afternoon energy load and stretching the high-load period to eight hours would reduce the maximum loading to about 108%. Energy use in periods other than the transformer's peak hour can thus reduce the ability of the transformer to carry peak demands and force the replacement of the unit or addition of new transformers.

Alternatively, if the transformer is loaded heavily enough that the useful life is reduced, reducing the pre-overload power flow and shortening the overload period would mitigate that reduction, extending the life of the equipment and reducing the rate of failure. This is particularly relevant for line transformers, for which the utility will not usually be able to closely monitor transformer loading and temperature.

Q: Does heavy loading affect the capacity of underground lines?

A: Yes. Heat builds up in conduit and around direct-buried lines, contributing to overheating and damage to the lines' insulation.

Q: Do the same issues apply to overhead lines?

A: Yes, although the mechanisms are different than for the underground lines and transformers. The capacity of overhead lines is often limited by the sagging caused by thermal expansion of the conductors, which also occurs more readily with summer peak conditions of high air temperatures, light winds and strong sunlight. Overheating and sagging also reduce the operating life of the conductors.

Q: For the second category of costs, what usage factors indirectly increase the costs of geographic expansion of the distribution system?

A: AEP Ohio and its predecessor companies historically extended service to connect customers based on the revenues that could be expected from the additional connected load. Since the investor-owned utilities did not find it economic to serve all areas of the state, rural households and businesses organized cooperatives, which now serve a large fraction of Ohio, as measured by the area of service territories.

AEP Ohio currently charges for "the cost of residential construction in excess of five thousand dollars for single-family residences and twenty-five hundred dollars per unit for multifamily residences".[23] This provision reflects the Company's greater willingness to invest in system extensions for large customers than for small customers.

Q: With regard to the third category of costs, which costs tend to be correlated with customer usage level but are not directly caused by customer usage?

A: Examples of this category would include bad debt, the costs associated with adding line transformers to avoid long runs of secondary with high loads, or the additional distribution costs between very large suburban homes, as opposed to close-packed urban duplexes or apartments.

The higher the customer's usage and bills, the more bad debt AEP Ohio will incur if the customer leaves without paying the final month's bill, or declares bankruptcy owing money to AEP Ohio.

The length of secondary runs permissible from transformers to customers depends on the load on the lines. Longer lines have higher voltage drop, and voltage drop rises with load, so small customers can be further from the transformer than can large customers. In order to serve a large load at acceptable voltage, AEP Ohio must install a transformer close to the customer's service drop. A single transformer can serve many small customers up and down the block, while large customers at the same locations would require multiple transformers.

---

[23] Ohio Power Company P.U.C.O. No. 20, Terms and Conditions of Service, 2nd Revised Sheet No. 103-7, available at www.aepohio.com/global/utilities/lib/docs/ratesandtariffs/Ohio/2017-04-28_AEP_Ohio_Standard_Tariff.pdf.

Q: How does the Company's proposal to increase the residential customer charge by $2 per month affect the energy rate?

A: Raising the customer charge by $5 per month reduces the energy rate by $4.85/MWh, and raising it by $10 (AEP Ohio's proposed base customer charge as of January 1, 2018) would reduce the energy rate by $9.7/MWh, or 0.97¢/kWh.[24] Existing riders would add about 43.3% to this effect, bringing the total reduction in the energy charge to 1.39¢/kWh. As a percentage of the total basic residential energy rate, (about 12.1¢/kWh for the Ohio Power zone and about 11.4¢/kWh for the Columbus Southern zone), this 1.39¢ reduction would be about 11.5% for Ohio Power and 12.2% for Columbus Southern.[25]

VI. RATE DESIGN PRINCIPLES AND THE IMPACTS OF A HIGHER CUSTOMER CHARGE

Q: Once cost-based customer and energy charges are calculated, what is the next step in designing rates?

A: The next step is to determine whether the customer charge and energy charge estimates derived from the cost of service analysis adhere to the Bonbright rate design principles, and whether they further the objectives of relevant Ohio energy policy. I focus specifically below on the impacts of AEP Ohio's proposal in relation to Bonbright criteria Criteria 6 and 7 that require rates to be designed "fairly" and to avoid "undue discrimination," criterion 8 that

---

[24] Workpapers for Exhibit DRG-10.

[25] Calculation of based on current energy rates in the Bill Calculation Spreadsheets on AEP Ohio's web site, available at www.aepohio.com/account/bills/rates/AEPOhioRatesTariffsOH.aspx.

focuses the rate design process on providing efficient price signals, and Ohio's energy policy reflected in ORC §4928.02.

Q: Please summarize the impacts of a higher residential customer charge on AEP's customers.

A: Even though the AEP Ohio proposal would not directly increase the Company's aggregate revenues, and hence is revenue-neutral, it would nonetheless significantly affect bills and the extent to which customers would be motivated or rewarded for investing in clean energy options.

As discussed in Section VI.A below, the vast majority of residential customers will pay more per month under AEP Ohio's proposal. Further, as explained in Section VI.B, the increased electric consumption resulting from the rate changes would offset years of energy efficiency investment and customers would face longer payback periods when they make these investments in the future. In order to maintain planned savings, AEP Ohio might need to increase energy-efficiency program rebates recovered through the Energy Efficiency and Peak Demand Reduction Cost Recovery Rider. Because of these effects, all customers would eventually shoulder higher costs for both the distribution investments required by higher load growth and the higher energy-efficiency incentives. For these reasons, AEP Ohio's proposal is inconsistent with long-standing ratemaking principles and Ohio energy policy.

A. Impacts on Customer Bills

Q: Has AEP Ohio provided comprehensive data showing the effect of its customer-charge proposal on residential bills?

A: No. In the testimony of witness David Gill, AEP Ohio presents bill effects for only three levels of energy usage: 1,000, 2,000 and 4,000 kWh per month.[26] He does not break these numbers down into smaller increments, or provide a window into the bill impacts for customers using less than 1,000 kWh per month. Further, Mr. Gill's summary shows the effect of all rate changes proposed in the Amended ESP, not just the increase in the customer charge.

But Mr. Gill's testimony on even this limited cross-section of energy users is misleading. Increasing the customer charge and decreasing the energy charge in any tariff (while collecting the same revenue) would increase the bills of low-use customers and reduce the bills of high-use customers. The only customers who experience no change—i.e. those who "break even"—are those using the average monthly energy. That break-even point for the Company's proposed change in rate design is about 1,031 kWh per month.[27] It is thus not surprising that Mr. Gill reported only a small increase for customers with 1,000 kWh usage and bill reductions for the higher consumption levels.

But this does not provide a representative or complete picture of the effects of the customer-charge increase for the vast majority of AEP Ohio's customers—most of whom use less than 1,000 kWh per month. As shown in

---

[26] Gill Direct at 12.

[27] Moore Direct at 13.

Table 2 below, 64.4% of the Company's residential customers use less than 1,000 kWh/month, 93.9% use less than 2,000 kWh, and over 99% use less than 4,000 kWh.[28]

Q: Have you produced a more complete and representative bill analysis for the proposed customer charge increase?

A: Yes. In Table 2, I report the effect of the proposal on customer bills, for each of the usage levels for which AEP Ohio provided data. The "Bill Change" column shows the bill impacts for various usage levels in two ways: first, the base rate impacts of the proposed $10 per month customer-charge increase and the 0.97¢/kWh energy-charge reduction; second, the impacts of both the base rates and the 43.3% adders to base revenues, which would yield an effective $14.33/month increase in the customer charge, and a drop in the energy charge by 1.39¢/kWh. This analysis excludes future expected changes in the adders. As shown in Table 2, over 64% of customers would experience an increase, about 40% would see an increase over $5/month, and about 11% would experience an increase of more than $10/month.

[28] It remains unclear how many customers actually use more than 4,000 kWh monthly, since AEP Ohio grouped all bills over 3,000 kWh into the highest block of the data in response to discovery requests. See Exhibit PLC-6, which I used to construct Table 2. At the rate at which the number of bills fall as energy use increases (about 17% for every 100 kWh increase in usage), only about 0.3% of the customers would use over 4,000 kWh.

Table 2: Effect of Proposed Customer Charge on Bills

kWh/ month	Total Bills	% of Customers	Cumulative %	Bill Change	
				Base Rate	Total Bill
0	3,406	0.4%	0.4%	$10.00	$14.33
0-100	20,113	2.2%	2.6%	$9.52	$13.63
100-200	26,110	2.9%	5.5%	$8.55	$12.24
200-300	47,777	5.3%	10.7%	$7.58	$10.85
300-400	67,424	7.4%	18.1%	$6.61	$9.46
400-500	70,543	7.8%	25.9%	$5.64	$8.07
500-600	72,644	8.0%	33.9%	$4.67	$6.68
600-700	75,498	8.3%	42.2%	$3.70	$5.29
700-800	74,308	8.2%	50.4%	$2.73	$3.90
800-900	67,810	7.5%	57.8%	$1.76	$2.51
900-1,000	60,033	6.6%	64.4%	$0.79	$1.12
1,000-1,100	51,258	5.6%	70.1%	($0.19)	($0.27)
1,100-1,200	43,453	4.8%	74.8%	($1.16)	($1.66)
1,200-1,300	36,507	4.0%	78.9%	($2.13)	($3.05)
1,300-1,400	30,558	3.4%	82.2%	($3.10)	($4.44)
1,400-1,500	25,916	2.9%	85.1%	($4.07)	($5.83)
1,500-1,600	22,046	2.4%	87.5%	($5.04)	($7.22)
1,600-1,700	18,514	2.0%	89.5%	($6.01)	($8.61)
1,700-1,800	15,807	1.7%	91.3%	($6.98)	($10.00)
1,800-1,900	13,265	1.5%	92.7%	($7.95)	($11.39)
1,900-2,000	11,077	1.2%	93.9%	($8.92)	($12.78)
2,000-2,100	9,336	1.0%	95.0%	($9.89)	($14.17)
2,100-2,200	7,709	0.8%	95.8%	($10.86)	($15.56)
2,200-2,300	6,283	0.7%	96.5%	($11.83)	($16.95)
2,300-2,400	5,270	0.6%	97.1%	($12.80)	($18.34)
2,400-2,500	4,298	0.5%	97.6%	($13.77)	($19.73)
2,500-2,600	3,565	0.4%	98.0%	($14.74)	($21.12)
2,600-2,700	3,029	0.3%	98.3%	($15.71)	($22.51)
2,700-2,800	2,422	0.3%	98.6%	($16.68)	($23.90)
2,800-2,900	1,981	0.2%	98.8%	($17.65)	($25.29)
2,900-3,000	1,632	0.2%	99.0%	($18.62)	($26.68)
>3,000	9,529	1.0%	100.0%	($26.38)	($48.22)

Source: Ex. PLC-6

Bill effect is computed for middle of range

>3,000 is computed for 4,500 kWh

Further, AEP Ohio's filings confirm that these increases compound over time. Table 3 reflects calculations derived from Mr. Gill's electronic workpapers[29] demonstrating that, even with the other expected rider changes, customers using more than 1,000 kWh will see lower bills, while customers using 250 kWh would experience 12% increases by mid-2018, and 40% by 2024, as shown in Table 3.[30]

Table 3: Percentage Total Bill Change From November 2016

Level of Usage	November 2016 Total Bill	June 2018 Total Bill	2016-2018 Change	2024 Total Bill	2016-2024 Change
	A	*B*	*c= b÷a−1*	*D*	*e = d÷a−1*
0	$12.91	$29.71	130%	$37.00	187%
50	$19.35	$35.24	82%	$42.24	118%
150	$32.23	$46.32	44%	$52.73	64%
250	$45.11	$57.39	27%	$63.21	40%
350	$57.99	$68.47	18%	$73.70	27%
450	$70.87	$79.54	12%	$84.18	19%
550	$83.75	$90.62	8%	$94.67	13%
800	$115.95	$118.30	2%	$120.88	4%
1,000	$141.71	$140.45	-1%	$141.85	0%
1,200	$167.47	$162.60	-3%	$162.82	-3%
1,500	$206.11	$195.83	-5%	$194.28	-6%
2,000	$270.51	$251.20	-7%	$246.71	-9%

Q: Do you have any other concerns with regard to these impacts on customer bills?

A: Yes. The Company proposes a 119% increase in the customer charge for residential customers between now and January 1, 2018. As shown in Table

[29] The file "typical Bill impacts DRG-7.xlsx," which are the workpapers for Exh. DRG-7.

[30] I changed the "level of usage" values in the electronic workpaper for Exh. DRG-7 (the Ohio Power SSO Impacts sheet) to the values shown in Table 3, copied columns *a, b, c* and *d,* and computed column *e.*

2, over 64% of customers would experience an increase, about 40% would see an increase over $5/month, and about 11% would experience an increase of more than $10/month. Despite Ms. Moore's testimony that "the Company is proposing to implement this charge in a gradual fashion"[31] these cannot be considered gradual changes, in contravention of longstanding ratemaking principles.

B. Impacts on Energy Use and Energy Efficiency

Q: Please summarize the impacts of AEP Ohio's proposal on energy efficiency?

A: The proposed rate design restructuring would send inefficient rate signals that encourage customers to consume more energy, setting Ohio's energy efficiency efforts back years. In addition, customers would face longer payback periods for energy-efficiency investments, likely reducing incentives to participate in AEP Ohio's new slate of energy efficiency programming.

Q: To what extent would the lower energy rate under the Company's proposed customer charge dampen price signals for conservation?

A: Residential customers respond to the price incentives created by the electrical rate structure. Those responses are generally measured as price elasticities, i.e., the ratio of the percentage change in consumption to the percentage change in price. Price elasticities are generally low in the short term and rise over several years, because customers have more options for increasing or reducing energy usage in the medium to long term. For example, a review by Espey and Espey (2004) of thirty-six articles on residential electricity

---

[31] Moore Direct at 13.

demand published between 1971 and 2000 reports short-run average-rate elasticity estimates of about −0.35 on average across studies and long-run average-rate elasticity estimates of about −0.85 on average across studies.[32]

Studies of electric price response typically examine the change in usage as a function of changes in the marginal rate paid by the customer. Table 4 lists the results of seven studies of marginal-price elasticity over the last forty years.[33]

Table 4: Summary of Marginal-Price Elasticities

Authors	Date	Elasticity Estimates
Acton, Bridger, and Mowill	1976	−0.35 to −0.7
McFadden, Puig, and Kirshner	1977	−0.25 non-electric heat −0.52 with space heat
Barnes, Gillingham, and Hageman	1981	−0.55
Henson	1984	–0.27 to –0.30
Reiss and White	2001	−0.39
Xcel Energy Colorado	2012	–0.3 (at years 2 and 3)
Li, Orans, Kahn-Lang, and Woo	2014	–0.13 in 3rd year of phased-in rate

Q: What would be a reasonable estimate of the marginal-price elasticity for changes in the residential energy rate?

A: From Table 4, it appears that –0.3 would be a reasonable mid-range estimate of the impact over a few years.

[32] Available at http://ageconsearch.tind.io//bitstream/42897/2/Espey%20JAAE%20April%202004.pdf. In other words, on average across these studies, consumption decreased by 0.35% in the short term and by 0.85% in the long term for every 1% increase in average rates.

[33] These studies (or links thereto) are in Exhibit PLC-7.

Q: What would be a reasonable estimate of the effect on energy use from the reduction to the energy rate under the Company's proposal?

A: An elasticity of –0.3 and the 11.5% reduction in energy price for Ohio Power would result in an increase in energy consumption of about 3.7%; with the 12.3% reduction for the Columbus Southern zone, energy consumption would be expected to rise 4%. This means that all else equal, residential load would be expected to increase by almost 4% over the next few years as a result of implementing the Company's proposed customer charge increase.[34]

For comparison, the Company's 2018 and 2019 goals for energy savings from its consumer sector programs with continuing savings amount to a reduction of about 0.73% of residential sales annually.[35] The consumption increase due to the Company's proposed increase to the residential customer charge (and the resulting decrease in the energy charge) would increase energy consumption enough to undo over five years of residential energy-efficiency savings. Since AEP Ohio is spending about $30 million annually on those programs, the increase in the customer charge would offset about $150 million of Company investment and some additional participant investments. The Company projects a utility cost test ratio (the ratio of avoided costs to utility spending) of about 3.0 for these programs, so

[34] Based on the change in the energy charge (0.97¢) plus the 43.3% adders (0.42¢), for a total of 1.39¢.

[35] Case No. 16-0574-EL-POR, *AEP Ohio 2017 to 2019 Energy Efficiency/Peak Demand Reduction (EE/PDR) Action Plan*, Exhibit JFW-1, June 15, 2016, Table 4. (Included in Ex. PLC-15.) I excluded the costs and benefits of the two programs that AEP did not consider to accumulate benefits, Behavior Change and Intelligent Home & Demand Response, and scaled the percentage of sales proportionately. The effects of rate-design changes, like those of the other efficiency programs, would last many years. Limiting the analysis to programs with long-term savings makes the comparison to rate-design incentives easier and clearer.

the lost present-value savings would be about $450 million. These data are summarized in Table 5.

Table 5: Projected Residential Energy-Efficiency Program Savings, Utility Cost and Benefit-Cost Ratio

	Incremental Annual Energy (GWh) Savings at Meter			Investments $M			Utility Cost Test Ratio
Program	**2017**	**2018**	**2019**	**2017**	**2018**	**2019**	
Appliance Recycling	11.8	11.9	11.9	$3.20	$3.40	$3.50	1.3
Community Assistance	8.4	8.5	8.5	$8.50	$8.50	$8.50	0.8
e3smart	6.8	6.8	6.9	$1.20	$1.20	$1.20	4
Efficient Products	64.5	61.1	57	$9.10	$8.70	$8.00	5.5
In-Home Energy	8.7	8.3	8.6	$5.30	$5.10	$5.20	1.8
New Home	4.7	4.8	6.1	$2.40	$2.40	$3.10	1.7
Manufactured Home	2.2	2.5	2.5	$0.70	$0.80	$0.80	2
Total	107.1	103.9	101.5	30.4	30.1	30.3	2.5

AEP Ohio 2017 to 2019 Energy Efficiency/Peak Demand Reduction (EE/PDR) Action Plan, June 15, 2016, Tables 4, 7 and 9. Exhibit PLC-15.

Q: Is your use of an elasticity of –0.3 critical in determining that AEP Ohio's proposal to increase the customer charge would impose large costs through increased consumption?

A: No. Even if the demand elasticity were much smaller, the costs would be substantial.

Q: Did the Company consider these impacts of the increased customer charged on energy conservation?

A: No. It appears that AEP has not conducted this inquiry.[36] Without any analysis, AEP Ohio suggests that the roughly 12% reduction in the energy charge "will maintain the opportunity for plenty of savings for lowering

[36] *See* Ex. PLC-8. (the Company responded that it has not performed the requested analyses – "any studies or documents available to the Company that estimate the extent to which a decrease in energy charges will increase energy usage by customers").

energy usage."[37] Certainly, customers could still save money by reducing usage, but those savings would be 12% smaller, weakening incentives to invest in efficient equipment, use setback thermostats, or be careful about using electricity.

Q: Would the change in rate design have any other effect on customer efficiency efforts?

A: Yes. Reducing the energy rate by about 12% would increase the payback period for investments in efficiency and alternative energy. A measure that would have a 5-year payback under current rates would have a 5.6 year payback period with the proposed rates.

Table 6 shows the effect of the reduction in energy costs on the payback periods for some residential energy-efficiency measures, from AEP Ohio's 2017–2019 Energy Efficiency/Peak Demand Reduction Action Plan. I selected measures that AEP Ohio included in its programs and that have at least a three-year payback period. Depending on the measure and the zone, paybacks increase from little more than 3 years to nearly four years, from under four years to about 4.5 years, and so on, up to under 10 years to over 11 years. [38]

[37] Ex. PLC-9.

[38] The 1.4¢/kWh difference in the energy rate includes the base decrease in the energy charge, and the 43.3% of current riders.

Table 6: Payback for Selected Energy-Efficiency Measures

					Energy Price			
Efficiency Measure	Annual Energy	Incentive	Incremental Cost	Participant Cost	**OP Zone**		**CSP Zone**	
					$0.121	$0.107	$0.114	$0.100
					now	*prop*	*now*	*prop*
	A	*B*	*C*	*d*	*e*	*f*	*g*	*h*
VSD Pool Pump	1,170	$200	$750	$550	3.9	4.4	4.1	4.7
Efficient Refrigerator (ENERGY STAR® or Better)	104	$50	$90	$40	3.2	3.6	3.4	3.8
ENERGY STAR® Freezer	36	$10	$35	$25	5.7	6.5	6.1	6.9
Clothes Washer - Tier 3 >= 2.2 MEF- w/gas or no dry	130	$50	$101	$51	3.3	3.7	3.5	4.0
High Performance Circulating Pump (DHW)	354	$50	$300	$250	5.8	6.6	6.2	7.1
Tier 2 GSHP, Closed Loop, water to air	653	$500	$1,203	$703	8.9	10.1	9.4	10.8
Ductless Mini Split HP SEER 18	159	$200	$377	$177	9.2	10.4	9.8	11.1
Duct Sealing and Insulation -Heat Pump	1,511	$70	$760	$690	3.8	4.3	4.0	4.6
ENERGY STAR® Double Pane Windows -Central A/C -Non-EL Heat	126	$50	$150	$100	6.6	7.4	7.0	7.9
Triple Pane Windows -Central A/C -Non-EL Heat	199	$75	$250	$175	7.3	8.2	7.7	8.8
Drain Water Heat Recovery (42% efficient or higher)	391	$250	$660	$410	8.7	9.8	9.2	10.5
ENERGY STAR® 3.0 Qualified Home - Heat Pump	3,389	$1,000	$2,329	$1,329	3.2	3.7	3.4	3.9

Sources:
Columns *a-c*: Exhibit PLC-16.
Column *d*: *b* – *a*
Columns e-h: *d* ÷ (*a* × *energy price*)

VII. OTHER CONCERNS WITH AEP OHIO'S PROPOSAL

A. Bill Volatility

Q: Does you agree with Ms. Moore that the Company's proposal will reduce bill volatility for some customers?

A: A higher fixed charge does reduce changes from one monthly bill to the next. But I disagree with the implication that increasing the customer charge would be a reasonable way to address bill volatility. As detailed in the prior sections of this testimony, the Company's proposal comes with high costs in efficiency and in equity, as smaller customers would be charged for equipment that is required only by the usage of larger customers.

Q: Does AEP Ohio provide another mechanism for customers who prefer to moderate volatility?

A: Yes. The Company offers an Average Monthly Payment ("AMP") plan, which it describes on its web site as follows:[39]

> The AMP plan significantly moderates the monthly bill variation while avoiding the potential of accumulating a large settlement balance, or credit, at the anniversary month. Please note that this is not an equal monthly payment plan.
>
> The monthly payment on the AMP Plan is based on the average of the current month's bill, plus the previous 11 months' bills. Each month, the oldest bill is removed from the computation, and the new current bill is included. As a result, the payment amount will fluctuate slightly from month to month.

[39] *See* https://www.aepohio.com/account/bills/manage/LevelPayments.aspx, at the "Learn more about our Average Monthly Payment Plan" link.

> The difference between actual billings and the average billings will be carried in a deferred balance that will accumulate both debit and credit differences for the duration of the AMP Plan year (12 consecutive months).
>
> At the anniversary month, the deferred balance is divided by 12, and this one-twelfth amount is added to (or subtracted from) the average payment amount for the next 12 months.

This smoothing process would provide customers who want stable bills a high level of stability, without reducing the rewards for conservation that would accompany a customer charge increase.

Q: Does revenue decoupling moderate the volatility of bills?

A: Yes. If sales are high due to extreme weather in one year, revenue decoupling (in the form of the Company's existing PTBAR) returns the excess revenues to customers in the next year. While the AMP program tamps down variability in a year, revenue decoupling smoothes out bills over multiple years.

B. PIPP and Low-Income Customers

Q: Has Ms. Moore demonstrated that the increased customer charge "will lower the PIPP bills, therefore lowering the future revenue requirement of the Universal Service Fund"?[40]

A: No. Ms. Moore's testimony notes that the average customer currently on the PIPP program use slightly more than the class average, so the Universal Service Fund charge would be marginally lower with a higher customer charge. She did not address the issue of whether an additional charge that may exceed $150 annually will push into the PIPP some customers who are

[40] Moore Direct at 13.

either: 1) not eligible now, but would be with the additional charge; or 2) are eligible now, but have not bothered to file for PIPP benefits, since their bills are so small, but would do so if their bills rose several dollars a month. The Company admitted that it has not done any analysis to determine whether the higher proposed customer charge would push currently eligible but non-participating customers into the PIPP plan.[41]

Q: How would AEP Ohio's proposed dramatic increase in the customer charge affect low-income customers?

A: The Company does not appear to know. It was unable to provide "any data on the bill frequency distribution of the Company's low-income residential customers, other than those on the Percentage of Income Payment Plan" and said that it "has not performed the requested analysis."[42]

This is a serious omission in AEP's filing. Given the significant impacts of the customer charge on monthly bills for those who use less than the average amount of electricity, it is critical that the Company evaluate who these customers are and the extent to which the impacts will disproportionately burden low-income Ohioans, those on fixed incomes, and other vulnerable customers. Without such foundational information, the Company cannot have legitimately addressed the needs of these customers or taken steps to address the regressive effects of its proposal.

[41] Ex. PLC-10.

[42] Ex. PLC-11.

VIII. DECOUPLING SALES FROM REVENUE

Q: What action does AEP Ohio request regarding revenue decoupling?

A: AEP Ohio witness Jon F. Williams requests that the Commission continue the PTBAR for residential and small commercial customers (on the GS1 rate) and expand the mechanism to include all commercial and industrial customers.[43] The PTBAR decouples the distribution revenue received by AEP Ohio from the energy consumption of its customers.

Q: What is your recommendation with respect to these requests?

A: I support those requests. The PTBAR trues up actual distribution revenue to allowed revenue, reducing sales risk to both AEP Ohio and customers, while removing the principle financial disincentive for AEP Ohio to support customers in reducing their usage through energy efficiency (through utility-sponsored programs or otherwise) and distributed energy resources, such as solar and other distributed generation.

Q: How does the PTBAR benefit customers?

A: The PTBAR provides two types of customer benefit. First, it reduces the volatility of electric bills with respect to weather. In a hot summer (and to some extent, in a cold winter), customer bills are higher for distribution and generation services, since customers will tend to use more kilowatt-hours.[44] Decoupling returns those excess revenues to customers.

Second, decoupling benefits customers by increasing the likelihood that AEP Ohio will pursue and support options that reduce customers' costs, even

---

[43] Williams Direct at 24–25.

[44] Customers with demand meters are also likely to experience higher demand charges.

while also reducing the Company's sales. Initiatives in this category could include:

- Utility energy-efficiency programs beyond mandated levels.
- Support for energy efficiency sponsored by other parties, such as building codes and efficiency standards.
- Behind-the-meter distributed generation.
- More effective rate designs, such as moving distribution rates from large non-residential customers away from demand charges and towards time-of-use energy charges.

Q: Are there any alternative regulatory approaches for delivering these benefits as effectively as revenue decoupling?

A: No. With a great deal of continuing attention to detail, the Commission could develop a mechanism for recovery of lost revenue from utility energy-efficiency programs and behind-the-meter distributed generation, but that would not help facilitate the other initiatives or provide revenue stability. Recovering more distribution revenues through customer charges would protect the utility against loss of revenues, but would result in inequitable and inefficient rate design, as I discuss above.

The general trend in recent years has been for regulators to move from lost-revenue mechanisms to decoupling, and to reject proposals to significantly increase customer charges, although there are always exceptions.

IX. CONCERNS WITH DEMAND CHARGES

Q: Do you agree with Ms. Moore's recommendation that residential distribution costs should ideally be collected in demand charges?[45]

A: No. There are several flaws in Ms. Moore's statements regarding demand charges, which I discuss below.

Q: How does AEP Ohio describe the cause and appropriate recovery of distribution costs that are not caused by the number of customers on the system?

A: Ms. Moore says that "Distribution costs are incurred by sizing the distribution system to meet customer(s) peak kW demand usage. These costs vary by peak demand requirements, not by kWh usage or by simply connecting a customer to the system. These costs would ideally be collected through a demand charge."[46]

I assume that, by "demand charge," Ms. Moore means a charge in $/kW or $/kVA for the customer's maximum rate of consumption over any 30-minute period in each month, regardless of when that event occurs.[47]

Q: Are demand charges a common component of residential rates?

A: No. While demand charges for commercial and industrial customers are common, regulated utilities that have demand charges for residential

---

45 Moore Direct at 13.

46 *Id.*

47 Some of AEP Ohio's demand rates include a ratchet provision, under which the billing demand each month is the greater of that month's maximum demand or a specified fraction of a previous month's maximum demand.

customers are extremely rare.[48] Even for the utilities that have installed meters that can measure customer maximum demand, regulators have generally preferred to use those meters to bill for energy (sometimes by time of use), rather than imposing a confusing, inequitable and inefficient demand charge.

Q: Is Ms. Moore correct about the cause and recovery of distribution costs?

A: Not entirely. Distribution costs are incurred in part by sizing the distribution system to meet high loads (including annual peak loads) on each piece of equipment, not the customers' individual maximum demands or the class peak load. Ms. Moore suggests that those costs, driven by loads in the hours in which the combined loads of several, hundreds, or thousands of customers (both residential and other classes) would ideally be collected through a demand charge that imposes costs on each customer when it hits its maximum demand for the month, whether that is at 11 pm on a Sunday or 5 am on a Wednesday.

Q: Has AEP Ohio provided any justification for Ms. Moore's position that costs that are driven by the coincident loads of many customers "should ideally be recovered through a non-coincident demand charge"?

A: No. To clarify Ms. Moore's statement, Ex. PLC-12 part B asked:

[48] Many non-residential customers are served by a dedicated transformer or bank of transformers, and a very large non-residential customer may be the dominant load on at least part of the feeder that serves it. Recovering a portion of distribution revenues through demand charges may better reflect cost causation for these customers than for residential customers.

> Please explain whether Witness Moore's reference to "customer(s) peak kW demand usage" means one of the following: (i) each customer's maximum monthly demand, whenever it occurs; (ii) each customer's maximum annual demand, whenever it occurs; (iii) the customers' collective maximum demand on the particular piece of distribution equipment; (iv) or something else.

Ms. Moore responded as follows, indicating that the AEP Ohio cost-of-service study assumes that three different kinds of peaks contribute to the costs of the distribution system:

> The statement is a general statement representing that the cost of service study in Case Nos. 11-351-EL-AIR and 11-352-EL-AIR provides for the peak demands in allocation of the distribution system. Some equipment is based on the coincident peak of the system while others are a combination of the non-coincident peak as well as the annual non-coincident peak.

Ms. Moore later clarified that "'Non-coincident peak' was referring to the class maximum demand and 'annual non-coincident peak' was referring to the sum of the individual customer maximum demand."[49] Thus, AEP Ohio allocates some the distribution costs on the system coincident peak (the estimated class loads at hours of the AEP Ohio maximum load for the year), some part on the class coincident peak (at the hour that AEP Ohio estimates the class reaches its maximum load) and some on the sum of customer maximum demands, at many different hours during the year.

Ex. PLC-12, parts C and D, asked:

> If Witness Moore's reference to "customer(s) peak kW demand usage" means each customer's maximum demand, regardless of timing, please explain how this measure of customer load determines the sizing of line transformers, feeders and substations.

[49] Ex. PLC-13.

> To the extent Witness Moore believes that a residential customer's maximum demand, whenever it occurs, determines the cost of distribution equipment, please explain how that would be the case for (i) the substation, (ii) the feeder; and (iii) the line transformer.

Ms. Moore's response provided no explanation for her claim that "These costs would ideally be collected through a demand charge," and simply described AEP Ohio's allocation method, without even offering any justification for the allocation method:

> The secondary distribution system (secondary lines, secondary components of line transformers) are allocated using 50% of the customer's maximum demand and 50% of the annual customers demand. The primary system (primary lines, primary components of the line transformers) as well as substations are allocated based on the peak load.[50]

It does not appear that AEP Ohio's allocation method is actually related to the factors that cause distribution costs, which include high and maximum loads in a variety of hours. If that method were cost-based, it would indicate that a majority of the distribution costs (100% of the substations and primary system, plus 50% of the secondary system) are driven by group peaks, not the individual customers' undiversified maximum demands.

Q: As a more general matter, would a demand charge be an appropriate method for recovering distribution costs?

A: No. A demand charge, as that term is generally used in utility practice, imposes a charge based on the customer's highest usage (usually over 15 minutes or one hour) at any time during the month (and in some cases, any time during the year). Demand charges are difficult to avoid and are therefore often grouped with customer charges in the category of "fixed charges,"

[50] The "peak load" here is contribution to 6 coincident peaks (Ex. PLC-14).

while energy charges are considered to be variable and subject to customer control.

Some utilities confuse ratemaking terminology, and assume that any cost classified as "demand-related" in an embedded cost-of-service study should be recovered through a demand charge, imposed on customers in proportion to their individual non-coincident maximum demand. In reality, demand-related costs are related to coincident peaks or other high loads on various transmission and distribution equipment, and are typically allocated on measures of coincident demands or proxies, such as class diversified peak loads.

A similar confusion arises in the conflation of two meanings of "fixed costs:"

Fixed Costs 1: costs invariant with respect to load or usage, and thus not avoidable by reducing load.

Fixed Costs 2: costs fixed over the year, not varying in the short run.

Many costs in any particular year are largely determined by the cumulative investment and construction commitments in the past, and are hence fixed by Definition 2. However, even though distribution costs are overwhelmingly fixed over the year, none of them are fixed over load, since plant is added to maintain reliability and reduce losses as load grows. Hence, they are not fixed by Definition 1 and should be recovered through rates that vary with usage and encourage customers to reduce and control the usage that contributes to the costs.

Q: Are demand charges helpful in providing price signals to ratepayers?

A: No. Demand charges are inappropriate for several reasons, including the following:

- Demand charges do not target peak demand reduction, since they apply to customer maximum demands, not to the times of system peaks or equipment maximum loads. Customer peaks occur at a wide variety of hours, on a wide variety of days, with many far from the coincident peaks on the distribution equipment.
- Demand charges do not provide appropriate incentives to conserve, even during the system's high-load hours.
- Not only are demand charges ineffective in shifting loads off high-cost hours, they may cause some customers to shift loads in ways that increase costs. For a customer who experiences its maximum summer demands at noon or 9 pm, a demand charge encourages the shifting of load into the afternoon peaks on the generation, transmission and distribution systems.
- Demand charges are very difficult for customers to understand, let alone mitigate. It is difficult to find an example of a product for which consumers pay based on their maximum usage rate.

Q: Please explain why demand charges do not provide the appropriate incentives.

A: Demand charges are a particularly ineffective means for giving price signals, for the following reasons:

- The demand-charge portion of the electric bill is determined by the customer's individual maximum demand. Capacity costs are driven by coincident loads at the times of the peak loads on each piece of equipment (substation, feeder, transformer), not by the non-coincident maximum demands of individual customers. The customer's individual peak hour is not likely to coincide with the peak hours of the other customers sharing a piece of equipment, especially since the peaks on the secondary system, line transformer, primary tap, feeder, substations, and sub-transmission lines occur at varying times.

- Demand charges provide little or no incentive to control or shift load from those times that are off the customers' peak hours but that are very much on the system peak hours. Customers can avoid demand charges merely by redistributing load within the peak period. Some of those customers will be shifting loads from their own peak to the peak hour on the local distribution system. This will cause customers to increase their contribution to maximum or critical loads on the local distribution system, the transmission system, and/or the regional generation system.
- Demand charges are difficult to avoid; even a single failure to control load results in the same demand charge as if the same demand had been reached in every day or every hour. This attribute of demand charges erodes the incentive to even try to avoid the charge, since weeks of careful effort can be swept away if the electric water heater and refrigerator happen to go on simultaneously. Once a customer is aware of having hit a high billing demand for the month, the demand charge offers no reward for controlling load any time that the customer's load is less that that prior demand.
- Rather than promoting conservation at high-cost times, or shifting of load from system peak periods, demand charges encourage customers to waste resources on the arbitrary tasks of flattening their personal maximum loads, even if those occur at low-cost times. For instance, in

order to respond to demand charges effectively, customers will need to install equipment to monitor loads, interrupt discretionary load, and schedule deferrable loads. Moreover, lower energy charges will encourage increased electric use, some of which will likely occur in the peak period.

Q: Does AEP Ohio have any residential tariff that uses a measure of demand?

A: Yes. Schedule RDMS (Residential Demand Metered Service) charges a lower energy price for energy used in excess of 400 hours times a monthly billing demand defined as "the number of kilowatts determined by dividing the number of kilowatt-hours used during the on-peak period in the month by the number of hours in such period."[51]

This is essentially a time-of-use rate that assumes that monthly energy consumption above 400 times the average load in the peak period would be less expensive to serve. Any energy used in the peak period would increase the threshold at which the rate falls to the lower price. The rate requires that AEP Ohio measure usage in the peak period, and it could be replaced by a simple time-of-use rate. Interestingly, this rate demonstrates a more useful approach to defining the customer load that imposes higher cost on the distribution system. By recognizing that usage any time in the peak period may result in heavy loads and heat buildup in various parts of the distribution system, including the customer's transformer, the feeder, the distribution

[51] Ohio Power Company P.U.C.O. No. 20, Terms and Conditions of Service, 6th Revised Sheet No. 213-1, available at www.aepohio.com/global/utilities/lib/docs/ratesandtariffs/Ohio/2017-04-28_AEP_Ohio_Standard_Tariff.pdf.

substation, (and potentially one or more higher-voltage distribution lines and substations).

Q: Ms. Moore proposes an opt-in demand charge for residential customers.[52] Is there any merit to this proposal?

A: No. The demand charge does not distinguish between a customer with a maximum demand of, for example, 7 kW at 11 pm once a month and an average of 3 kW on the high-load hours for the distribution equipment, or 7 kW every day in the distribution high load from 10 am to 9 pm and an average of 5 kW the rest of the month. The second customer puts much more stress on the system but pays no more for doing so. As I explained above, the demand charge may just encourage customers to shift load off their own peak hours (which may occur at 6 am or midnight) onto the peak hours of various distribution equipment.

It is my understanding that AEP Ohio has deployed meters with extensive billing capability, which should be used to charge customers for usage at the times that cause costs, through time-of-use or other time-varying rates, rather than to implement a 19th century rate design, developed when time-of-use was not feasible. Even as an optional test, AEP Ohio should be concentrating its efforts on more efficient rate designs.

X. RECOMMENDATIONS

Q: Please summarize your recommendations in this proceeding.

A: I recommend that the Commission:

- Reject the Company's proposal to increase the customer charge and decrease the energy charge.

---

[52] Moore Direct at 14.

- Approve the Company's request to extend and broaden the PTBAR mechanism.

Q: Do you have any recommendations regarding subsequent proceedings?

A: Yes. It is my understanding that the Commission is currently undertaking an initiative called PowerForward, focused on reviewing and modernizing Ohio's infrastructure and processes. AEP Ohio's rate design proposal could very likely limit options in that initiative for optimizing the grid and providing the best outcomes for consumers. Thus, I recommend that, in addition to rejecting AEP Ohio's proposal, the Commission consider exploring alternative rate designs as part of PowerForward that can move Ohio toward more efficient options, such as reducing customer and demand charges and recovering more revenue through time-varying rates supported by AEP Ohio's advanced metering. As part of that process, the Commission could consider in future cases the revision of some riders, so that rate increases will fall more on energy charges and less on customer and demand charges.

In addition, before any further rate proposals are made, I recommend that the Commission require that AEP Ohio (or any other utility, for that matter) collect information on the frequency of low-income customers by usage level, not limited to PIPP participants. In addition, the Company should insure that its load-research program includes enough low-income customers to allow for statistically reliable estimates of the load shapes of that group. Such information will allow the Commission to avoid inadvertently burdening low-income customers in the rate design process, including potential future introduction of time-varying rates.

Q: Does this conclude your direct testimony?

A: Yes.

CERTIFICATE OF SERVICE

I hereby certify that a true copy of the foregoing *Direct Testimony of Paul L. Chernick* submitted on behalf of Natural Resource Defense Council was served by electronic mail upon the following Parties of Record on May 2, 2017.

/s/ Robert Dove
Robert Dove

Counsel for Natural Resources Defense Council

SERVICE LIST

Bojko@carpenterlipps.com
perko@carpenterlipps.com
mfleisher@elpc.org
cmooney@ohiopartners.org
paul@carpenterlipps.com
mleppla@theOEC.org
tdougherty@theOEC.org
lhawrot@spilmanlaw.com
dwilliamson@spilmanlaw.com
charris@spilmanlaw.com
ibatikov@vorys.com
whitt@whitt-sturtevant.com
campbell@whitt-sturtevant.com
glover@whitt-sturtevant.com
tony.mendoza@sierraclub.org
dborchers@bricker.com
eakhbari@bricker.com
sechler@carpenterlipps.com
cpirik@dickinsonwright.com
todonnell@dickinsonwright.com
wvorys@dickinsonwright.com
werner.margard@ohioattorneygeneral.gov
Robert.eubanks@ohioattorneygeneral.gov
Kevin.moore@occ.ohio.gov

Attorney Examiners:
Greta.see@puc.state.oh.us
Sarah.parrot@puc.state.oh.us

stnourse@aep.com
msmckenzie@aep.com
fdarr@mwncmh.com
mpritchard@mwncmh.com
Kurt.Helfrich@ThompsonHine.com
Stephanie.Chmiel@ThompsonHine.com
Michael.Austin@ThompsonHine.com
mkurtz@BKLlawfirm.com
kboehm@BKLlawfirm.com
jkylercohn@BKLlawfirm.com
rick.sites@ohiohospitals.org
mwarnock@bricker.com
dparram@bricker.com
william.michael@occ.ohio.gov
rsahli@columbus.rr.com
mjsettineri@vorys.com
glpetrucci@vorys.com
ibatikov@vorys.com
joliker@igsenergy.com
mdortch@kravitzllc.com
amy.spiller@duke-energy.com
Elizabeth.watts@duke-energy.com
joe.halso@sierraclub.org
ajay.kumar@occ.ohio.gov
dstinson@bricker.com

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.

"The Price is Right: Restructuring Gain from Market Valuation of Utility Generating Assets" (with Jonathan Wallach), *International Association for Energy Economics Seventeenth Annual North American Conference* (345–352). Cleveland, Ohio: USAEE. 1996.

"The Future of Utility Resource Planning: Delivering Energy Efficiency through Distributed Utilities" (with Jonathan Wallach), *International Association for Energy Economics Seventeenth Annual North American Conference* (460–469). Cleveland, Ohio: USAEE. 1996.

"The Future of Utility Resource Planning: Delivering Energy Efficiency through Distribution Utilities" (with Jonathan Wallach), *1996 Summer Study on Energy Efficiency in Buildings,* Washington: American Council for an Energy-Efficient Economy 7(7.47–7.55). 1996.

"The Allocation of DSM Costs to Rate Classes," *Proceedings of the Fifth National Conference on Integrated Resource Planning*. Washington: National Association of Regulatory Utility Commissioners. May 1994.

"Environmental Externalities: Highways and Byways" (with Bruce Biewald and William Steinhurst), *Proceedings of the Fifth National Conference on Integrated Resource Planning.* Washington: National Association of Regulatory Utility Commissioners. May 1994.

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

"Benefit-Cost Ratios Ignore Interclass Equity" (with others), *DSM Quarterly*, Spring 1992.

"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.

"Monetizing Environmental Externalities for Inclusion in Demand-Side Management Programs" (with Emily Caverhill), *Proceedings from the Demand-Side Management and the Global Environment Conference*, April 1991.

"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.

"The Valuation of Environmental Externalities in Utility Regulation" (with Emily Caverhill), *External Environmental Costs of Electric Power: Analysis and Internalization*. Springer-Verlag; Berlin: 1991.

"Analysis of Residential Fuel Switching as an Electric Conservation Option" (with Eric Espenhorst and Ian Goodman), *Gas Energy Review*, December 1990.

"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.

"The Relevance of Regulatory Review of Utility Planning Prudence in Major Power Supply Decisions," in *Current Issues Challenging the Regulatory Process*, Center for Public Utilities, Albuquerque, New Mexico, April 1987, pp. 36–42.

"Power Plant Phase-In Methodologies: Alternatives to Rate Shock," in *Proceedings of the Fifth NARUC Biennial Regulatory Information Conference*, National Regulatory Research Institute, Columbus, Ohio, September 1986, pp. 547–562.

"Assessing Conservation Program Cost-Effectiveness: Participants, Non-participants, and the Utility System" (with A. Bachman), *Proceedings of the Fifth NARUC Biennial Regulatory Information Conference*, National Regulatory Research Institute, Columbus, Ohio, September 1986, pp. 2093–2110.

"Forensic Economics and Statistics: An Introduction to the Current State of the Art" (with Eden, P., Fairley, W., Aller, C., Vencill, C., and Meyer, M.), *The Practical Lawyer*, June 1 1985, pp. 25–36.

"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.

"Insurance Market Assessment of Technological Risks" (with Meyer, M., and Fairley, W) *Risk Analysis in the Private Sector*, pp. 401–416, Plenum Press, New York 1985.

"Revenue Stability Target Ratemaking," *Public Utilities Fortnightly*, February 17 1983, pp. 35–39.

"Capacity/Energy Classifications and Allocations for Generation and Transmission Plant" (with M. Meyer), *Award Papers in Public Utility Economics and Regulation*, Institute for Public Utilities, Michigan State University 1982.

Design, Costs and Acceptability of an Electric Utility Self-Insurance Pool for Assuring the Adequacy of Funds for Nuclear Power Plant Decommissioning Expense, (with Fairley, W., Meyer, M., and Scharff, L.) (NUREG/CR-2370), U.S. Nuclear Regulatory Commission, December 1981.

Optimal Pricing for Peak Loads and Joint Production: Theory and Applications to Diverse Conditions (Report 77-1), Technology and Policy Program, Massachusetts Institute of Technology, September 1977.

REPORTS

"Charge Without a Cause? Assessing Electric Utility Demand Charges on Small Consumers" (with John T. Colgan, Rick Gilliam, Douglas Jester and Mark LeBel). Electricity Rate Design Review No. 1, July 2016.

"Implications of the Proposed Clean Power Plan for Arkansas: Review of Stakeholder Concerns and Assessment of Feasibility." 2014. Report to Arkansas Audubon, Arkansas Public Policy Panel, and Arkansas Sierra Club.

"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.

"Affordability of Pollution Control on the Apache Coal Units: Review of Arizona Electric Power Cooperative's Comments on Behalf of the Sierra Club" (with Ben Griffiths). 2012. Filed as part of comments in Docket EPA-R09-OAR-2012-0021 by National Parks Conservation Association, Sierra Club, et al.

"Audubon Arkansas Comments on Entergy's 2012 IRP." 2012. Prepared for and filed by Audubon Arkansas in Arkansas PUC Docket No. 07-016-U.

"Economic Benefits from Early Retirement of Reid Gardner" (with Jonathan Wallach). 2012. Prepared for and filed by the Sierra Club in PUC of Nevada Docket No. 11-08019.

“Analysis of Via Verde Need and Economics.” 2012. Appendix V-4 of public comments of the Sierra Club et al. in response to November 30 2011 draft of U.S. Army Corps of Engineers environmental assessment in Department of the Army Environmental Assessment and Statement of Finding for Permit Application SAJ-2010-02881.

“Comments for The Alliance for Affordable Energy on Staff’s ‘Proposed Integrated Resource Planning Rules for Electric Utilities in Louisiana.’” 2011. Filed by the Alliance for Affordable Energy in Louisiana PSC Docket R-30021.

“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.

“Risk Analysis of Procurement Strategies for Residential Standard Offer Service” (with Jonathan Wallach, David White, and Rick Hornby) report to Maryland Office of People’s Counsel. 2008. Baltimore: Maryland Office of People’s Counsel.

“Avoided Energy Supply Costs in New England: 2007 Final Report” (with Rick Hornby, Carl Swanson, Michael Drunsic, David White, Bruce Biewald, and Jenifer Callay). 2007. Northborough, Mass.: Avoided-Energy-Supply-Component Study Group, c/o National Grid Company.

“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.

"Estimation of Market Value, Stranded Investment, and Restructuring Gains for Major Massachusetts Utilities" (with Susan Geller, Rachel Brailove, Jonathan Wallach, and Adam Auster). 1996. On behalf of the Massachusetts Attorney General (Boston).

From Here to Efficiency: Securing Demand-Management Resources (with Emily Caverhill, James Peters, John Plunkett, and Jonathan Wallach). 1993. 5 vols. Harrisburg, Penn: Pennsylvania Energy Office.

"Analysis Findings, Conclusions, and Recommendations," vol. 1 of "Correcting the Imbalance of Power: Report on Integrated Resource Planning for Ontario Hydro" (with Plunkett, John, and Jonathan Wallach), December 1992.

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

“Review of the Elizabethtown Gas Company’s 1992 DSM Plan and the Demand-Side Management Rules” (with Jonathan Wallach, John Plunkett, James Peters, Susan Geller, Blair. Hamilton, and Andrew Shapiro). 1992. Report to the New Jersey Department of Public Advocate.

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

"Rethinking Utility Rate Design—Retail Demand and Energy Charges," Solar Power PV Conference, Boston MA, February 24, 2016.

"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.

"Cost-Effectiveness Analysis." 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.

"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." Demand-Side Management and the Global Environment Conference; Washington, D.C. April 22 1991.

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.

New England Gas Association Gas Utility Managers' Conference. Woodstock, Vermont, September 10 1990.

"Quantifying and Valuing Environmental Externalities." Presentation at the Lawrence Berkeley Laboratory Training Program for Regulatory Staff, sponsored by the U.S. Department of Energy's Least-Cost Utility Planning Program; Berkeley, California, February 2 1990;

"Conservation in the Future of Natural Gas Local Distribution Companies." District of Columbia Natural Gas Seminar; Washington, D.C. May 23 1989.

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

New England Conference of Public Utilities Commissioners, Environmental Externalities Workshop. Portsmouth, New Hampshire, January 22–23 1989.

"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".

"Reviewing Utility Supply Plans." Massachusetts Energy Facilities Siting Council; Boston, Massachusetts. May 30 1985.

"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.

ADVISORY ASSIGNMENTS TO REGULATORY COMMISSIONS

District of Columbia Public Service Commission, Docket No. 834, Phase II; Least-cost planning procedures and goals. August 1987 to March 1988.

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.

Puerto Rico Energy Commission, Puerto Rico Electric Power Authority, rate design issues, September 2015 to present.

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 DE 81-312, 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 Consumer 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** M01439, 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** M01496, 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. Also filed and presented in **MA EFSB** 08-02, February 2010.

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 M02961, 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 M03665, 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** M03665, 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 M**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** M04104; 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** M04175, 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. **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.

296. **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.

297. **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.

298. **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.

299. **Ky. PSC** 2014-00371, Kentucky Utilities electric rates; Sierra Club. March 2015.

Review basis for higher customer charges, including cost allocation. Design of time-of-day rates.

300. **Ky. PSC** 2014-00372, Louisville Gas and Electric electric rates; Sierra Club. March 2015.

Review basis for higher customer charges, including cost allocation. Design of time-of-day rates.

301. **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.

302. **N.S. UARB** M06733, supply agreement between Efficiency One and Nova Scotia Power; Nova Scotia Consumer Advocate. June 2015.

Avoided costs. Cost-effectiveness screening of DSM. Portfolio design. Affordability and bill effects.

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. **Ont. Energy Board** EB-2015-0029/0049, 2015–2020 DSM Plans Of Enbridge Gas Distribution and Union Gas, Green Energy Coalition. Evidence July 31, 2015, Corrected August 12, 2015.

Avoided costs: price mitigation, carbon prices, marginal gas supply costs, avoidable distribution costs, avoidable upstream costs (including utility-owned pipeline facilities).

305. **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.

306. **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.

307. **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.

308. **N.S. UARB** Matter No. M07176, NS Power 2016 Capital Expenditures Plan, Nova Scotia Consumer Advocate. February 2016.

Economic evaluation of proposed projects, including replacement energy costs and modeling of equipment failures. Treatment of capitalized overheads and depreciation cash flow in computation of rate effects of spending plan.

309. **Md. PSC** Case No. 9406, BGE Application for recovery of Smart Meter costs, Maryland Office of People's Counsel. Direct February 2016, Rebuttal March 2016, Surrebuttal March 2016.

Assessment of benefits of Smart Meter programs for energy revenue, load reductions and price mitigation; capacity load reductions and price mitigation; free riders and load shifting in peak-time rebate (PTR) program; cost of PTR participation; effect of load reductions on PJM capacity obligations, capacity prices and T&D costs.

310. **City of Austin TX**, Austin Energy 2016 Rate Review, Sierra Club and Public Citizen. May 2016

Allocation of generation costs. Residential rate design. Geographical rate differentials. Recognition of coal-plant retirement costs.

311. **Manitoba PUB**, Manitoba Hydro Cost of Service Methodology Review, Green Action Centre. June 2016, reply August 2016.

Allocation of generation costs. Identifying generation-related transmission assets. Treatment of subtransmission. Classification of distribution lines. Allocation of distribution substations and lines. Customer allocators. Shared service drops.

312. **Md. PSC** Case No. 9418, PEPCo Application for recovery of Smart Meter costs, Maryland Office of People's Counsel. Direct July 2016, Rebuttal August 2016, Surrebuttal September 2016.

Assessment of benefits of Smart Meter programs for energy revenue, load reductions and price mitigation; load reductions in dynamic-pricing (DP) program; cost of DP participation; effect of load reductions on PJM capacity obligations, capacity prices and T&D costs.

313. **Md. PSC** Case No. 9424, Delmarva P&L Application for recovery of Smart Meter costs, Maryland Office of People's Counsel. Direct September 2016, Rebuttal October 2016, Surrebuttal October 2016.

Estimation of effects of Smart Meter programs—dynamic pricing (DP), conservation voltage reduction and an informational program—on wholesale revenues, wholesale prices and avoided costs; estimating load reductions from the DP program; cost of DP participation; effect of load reductions on PJM capacity obligations, capacity prices and T&D costs.

314. **N.H. PUC** Docket No. DE 16-576, Alternative Net Metering Tariffs, Conservation Law Foundation. Direct October 2016, Reply December 2016.

Framework for evaluating rates for distributed generation. Costs avoided and imposed by distributed solar. Rate design for distributed generation.

315. **Puerto Rico Energy Commission** CEPR-AP-2015-0001, Puerto Rico Electric Power Authority rate proceeding, PR Energy Commission. Report December 2016.

Comprehensive review of structure of electric utility, cost causation, load data, cost allocation, revenue allocation, marginal costs, retail rate designs, identification and treatment of customer subsidies, structuring rate riders, and rates for distributed generation and net metering.

316. **N.S. UARB** Matter No. M07745, NS Power 2017 Capital Expenditures Plan, Nova Scotia Consumer Advocate. January 2017.

Computation and presentation of rate effects. Consistency of assumed plant operation and replacement power costs. Control of total cost of small projects. Coordination of information-technology investments. Investments in biomass plant with uncertain future.

317. **N.S. UARB** Matter No. M07746, NS Power Enterprise Resource Planning project, Nova Scotia Consumer Advocate. February 2017.

Estimated software project costs. Costs of internal and contractor labor. Affiliate cost allocation.

318. **N.S. UARB** Matter No. M07767, NS Power Advanced Metering Infrastructure projects, Nova Scotia Consumer Advocate. February 2017.

Design and goals of the AMI pilot program. Procurement. Coordination with information-technology and software projects.

319. **Québec** Régie de L'énergie R-3876-2013 phase 3A; Gaz Métro estimates of marginal O&M costs; Regroupement des organismes environnementaux en énergie. March 2017.

Estimation of one-time, continuing and periodic customer-related operating and maintenance cost. Costs related to loads and revenues. Dealing with lumpy costs.

320. **N.S. UARB** Matter No. M07718, NS Power Maritime Link Cost Recovery, Nova Scotia Consumer Advocate. April 2017.

Usefulness of transmission interconnection prior to operation of the associated power plant.

321. **Mass. DPU** 17-05, Eversource Rate Case, Cape Light Compact. May 2017.

Critique of proposed performance-based ratemaking mechanism. Proposal for improvements.

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

PLC 5/2/2017

AMERICAN ELECTRIC POWER

Legal Department

American Electric Power
1 Riverside Plaza
Columbus, OH 43215-2373
AEP.com

July 9, 2015

Barcy F. McNeal
Docketing Division Chief
Public Utilities Commission of Ohio
180 East Broad Street
Columbus Ohio 43215-3793

Matthew J. Satterwhite
Senior Counsel –
(614) 716-1915 (P)
(614) 716-2014 (F)
mjsatterwhite@aep.com

Re: Re: In the Matter of Ohio Power Company Revenue Neutral Residential Distribution Rate Design, Case No. 11-351-EL-AIR, Case No. 11-352-EL-AIR, Case No. 11-353-EL-ATA, Case No. 11-354-EL-ATA, Case No. 11-356-EL-AAM, Case No. 11-358-EL-AAM.

Dear Docketing Chief McNeal:

Background

On December 14, 2011, the Commission issued an Opinion and Order in these cases requiring Ohio Power Company (AEP Ohio or the Company) to update its cost-of-service study and file the updated study in this proceeding to review residential rate design at the end of the 3-year pilot revenue decoupling program. In addition, the Commission directed the Company to file, in Case No. 10-3126-EL-UNC, metrics to evaluate the success of the pilot program. The Company filed in that case as directed and that case is now closed based on the Commission determining that a straight fixed variable approach was to be filed by the electric utilities in their next base case. The Commission then narrowed its focus in the February 14, 2012 Entry on Rehearing in Case No. 11-351-EL-AIR determining that the Company recognize the Commission's focus on moving to a straight-fixed-variable rate in the future. As such the Company provides the following information to compare the pilot throughput balancing adjustment rider to a straight fixed variable rate design in compliance with the Commission's order in Case No. 11-351-EL-AIR.

Updated Cost-of-Service Study

Consistent with the Commission's directives, the Company is submitting a jurisdictional cost-of-service study for calendar year 2014 as Attachment 1 of this filing. This cost-of-service study does not include all adjustments typically made during a distribution rate case. It does, however, include an adjustment to remove the Company's revenues under the Pilot Throughput Balancing Adjustment Rider (PTBAR) and an adjustment to gross 2014 revenues to the level that would have been achieved had the Company instituted a Straight Fixed Variable (SFV) rate design.

Distribution Revenues

The Company has included the following riders in the study's Distribution per Books amount for the Distribution Firm Sales and Rider Revenues Line:

Universal Service Fund Rider
KWH Tax Rider
Residential Distribution Credit Rider
Pilot Throughput Balancing Adjustment Rider
Deferred Asset Phase-In Rider
Transmission Cost Recovery Rider*
Economic Development Rider
Enhanced Service Reliability Rider
GridSMART Phase 1 Rider
Distribution Investment Rider
Storm Damage Recovery Rider
Energy Efficiency and Peak Demand Reduction Cost Rider*

* The Transmission Cost Recovery Rider and the Energy Efficiency and Peak Demand Reduction Cost Rider were removed from revenues via adjustments included in Column 3 of Attachment 1 – Distribution Fixed, Known & Measurable Adjustments.

SFV Rate Design

The use of a Straight Fixed Variable rate design yields a Residential distribution charge of $27.24 per bill for a standard residential customer and a GS-1 distribution charge of $14.81 per bill for standard GS-1 customer. The rate design, which reflects the revenue requirements and billing determinants from Case Nos. 11-351-EL-AIR and 11-352-EL-AIR, along with the cost-of-service revenue adjustment are included in Attachment 2 of this filing.

Change in Pilot Throughput Balancing Adjustment Rider

The table below summarizes the effect of the net adjustments that remove the PTBAR accrual and replace it with an increase in revenues that would have resulted from the use of a SFV rate design for Residential and GS-1 customers.

Adjusted Operating Revenues – Sales of Electricity	$1,214,291,151	100%
Adjustment to Remove PTBAR Revenues	22,989,212	2%
Adjusted Distribution Revenues, excl. PTBAR	1,191,301,939	98%
Distribution Adjustment to Reflect SFV*	26,184,024	2%
Adjusted Operating Revenues – After SFV Adjustment	$1,217,485,964	100%

*Calculated in Attachment 2 of this filing

The Company provides this information as indicated by the Commission as a compliance filing related to the enumerated cases and is not seeking any change to the Pilot Throughput Balancing Adjustment Rider or other rates at this time.

Cordially,

/s/Matthew J. Satterwhite
Matthew J. Satterwhite
Senior Counsel

cc: Parties of Record

Ohio Power Company - Distribution
Jurisdictional Separation Study
Twelve Months Ended December 31, 2014

Line No.	Description (1)	DISTRIBUTION PER BOOKS (2)	DISTRIBUTION FIXED, KNOWN & MEASURABLE ADJUSTMENTS (3)	DISTRIBUTION AFTER ADJUSTMENT (4)	DISTRIBUTION ADJUSTMENT TO REMOVE PTBAR (5)	DISTRIBUTION AFTER PTBAR ADJUSTMENT (6)	DISTRIBUTION ADJUSTMENT TO REFLECT SFV (7)	DISTRIBUTION AFTER SFV ADJUSTMENT (8)	ALLOCATOR (9)	% (10)
1	Operating Revenues - Sale of Electricity	2,864,176,800	(1,649,885,649)	1,214,291,151	(22,989,212)	1,191,301,939	26,184,024	1,217,485,964		
2	Other Electric Operating Revenues	(37,578,867)	72,811,190	35,232,324	0	35,232,324	0	35,232,324		
3	Non-Firm Sales Revenues	387,387,235	(387,387,235)	0	0	0	0	0		
4	Total Operating Revenues	3,213,985,168	(1,964,461,693)	1,249,523,475	(22,989,212)	1,226,534,263	26,184,024	1,252,718,287		
5	Operation and Maintenance Expenses									
6	Power Production	1,474,368,257	(1,438,651,850)	35,716,407	0	35,716,407	0	35,716,407		
7	Transmission	272,544,016	(272,544,016)	0	0	0	0	0		
8	Distribution	188,235,870	(255,290)	187,980,580	0	187,980,580	0	187,980,580		
9	Customer Accounts	239,731,633	0	239,731,633	0	239,731,633	0	239,731,633		
10	Customer Service & Information	80,888,992	(71,913,433)	8,975,559	0	8,975,559	0	8,975,559		
10	Sales Expense	2,236,374	0	2,236,374	0	2,236,374	0	2,236,374		
11	Administrative and General	74,864,933	0	74,864,933	0	74,864,933	0	74,864,933		
12	Total Operation and Maintenance Expense	2,332,870,075	(1,783,364,588)	549,505,487	0	549,505,487	0	549,505,487		
13	Depreciation and Amortization Expense	137,337,855	0	137,337,855	0	137,337,855	0	137,337,855		
14	Regulatory Debits/Credits	109,974,399	(107,272,453)	2,701,946	(876,914)	1,825,032	0	1,825,032		
15	Taxes Other than Income	298,559,293	0	298,559,293	0	298,559,293	0	298,559,293		
16	Other	30,232,188	0	30,232,188	0	30,232,188	0	30,232,188		
17	Total Other Expenses	576,103,734	(107,272,453)	468,831,281	(876,914)	467,954,367	0	467,954,367		
18	Net Operating Income Before Income Tax	305,011,359	(73,824,652)	231,186,707	(22,112,298)	209,074,409	26,184,024	235,258,433		
19	State Income Tax	(4,868,952)	325,447	(4,543,505)	(206,620)	(4,750,125)	254,771	(4,495,354)		
20	Deferred State Income Tax	16,658,726	(1,043,761)	15,614,965	(8,532)	15,606,433	0	15,606,433		
21	Total State Income Tax	11,789,774	(718,314)	11,071,460	(215,152)	10,856,308	254,771	11,111,079		
22	Federal Income Tax									
23	Current Federal Income Tax	38,407,932	11,592,824	50,000,756	(7,360,067)	42,640,689	9,075,239	51,715,928		
24	Deferred Federal Income Tax	30,761,505	(37,180,042)	(6,418,537)	(303,934)	(6,722,471)	0	(6,722,471)		
25	Deferred Investment Tax Credit	(92,654)	0	(92,654)	0	(92,654)	0	(92,654)		
26	Total Federal Income Taxes	69,076,784	(25,587,218)	43,489,566	(7,664,001)	35,825,565	9,075,239	44,900,804		
27	Net Operating Income	224,144,801	(47,519,120)	176,625,681	(14,233,145)	162,392,536	16,854,014	179,246,551		
28	Electric Plant in Service - Original Cost	4,383,785,604	0	4,383,785,604	0	4,383,785,604	0	4,383,785,604		
29	Accumulated Provision for Depreciation & Amortization	(1,611,696,149)	0	(1,611,696,149)	0	(1,611,696,149)	0	(1,611,696,149)		
30	Construction Work in Progress	113,868,345	0	113,868,345	0	113,868,345	0	113,868,345		
31	Working Capital Requirement	9,799,995	0	9,799,995	0	9,799,995	0	9,799,995		
32	Other Rate Base Offsets	(835,390,008)	0	(835,390,008)	0	(835,390,008)	0	(835,390,008)		
33	Rate Base	2,060,367,786	0	2,060,367,786	0	2,060,367,786	0	2,060,367,786		

Ohio Power Company - Distribution
Jurisdictional Separation Study
Twelve Months Ended December 31, 2014

Line No.	Description (1)	DISTRIBUTION PER BOOKS (2)	DISTRIBUTION FIXED, KNOWN & MEASURABLE ADJUSTMENTS (3)	DISTRIBUTION AFTER ADJUSTMENT (4)	DISTRIBUTION ADJUSTMENT TO REMOVE PTBAR (5)	DISTRIBUTION AFTER PTBAR ADJUSTMENT (6)	DISTRIBUTION ADJUSTMENT TO REFLECT SFV (7)	DISTRIBUTION AFTER SFV ADJUSTMENT (8)	ALLOCATOR (9)	% (10)
1	Development of Rate Base									
2	Electric Plant in Service									
3	Intangible Plant									
4	A301 Organization costs	3,379	0	3,379	0	3,379	0	3,379	Direct	
5	A302 Franchises and Consents	4,700	0	4,700	0	4,700	0	4,700	Direct	
6	A303 Miscellaneous Intangible Plant	81,456,551	0	81,456,551	0	81,456,551	0	81,456,551	Direct	
7	Total Intangible Plant	81,464,630	0	81,464,630	0	81,464,630	0	81,464,630		
8	Production Plant									
9	Steam & Hydraulic (A300s to A340s)	0	0	0	0	0	0	0	N/A	
10	Total Production Plant	0	0	0	0	0	0	0		
11	Transmission Plant									
12	A350 Land and Land Rights	0	0	0	0	0	0	0	N/A	
13	A352 Structures and Improvements	0	0	0	0	0	0	0	N/A	
14	A353 Station Equipment	0	0	0	0	0	0	0	N/A	
15	A354 Towers and Fixtures	0	0	0	0	0	0	0	N/A	
16	A355 Poles and Fixtures	0	0	0	0	0	0	0	N/A	
17	A356 O.H. Conductors & Devices	0	0	0	0	0	0	0	N/A	
18	A357 Underground Conduit	0	0	0	0	0	0	0	N/A	
19	A358 Underground Conductors	0	0	0	0	0	0	0	N/A	
20	A359 Roads and Trails	0	0	0	0	0	0	0	N/A	
21	Total Transmission Plant	0	0	0	0	0	0	0		

Ohio Power Company - Distribution
Jurisdictional Separation Study
Twelve Months Ended December 31, 2014

Line No.	Description (1)	DISTRIBUTION PER BOOKS (2)	DISTRIBUTION FIXED, KNOWN & MEASURABLE ADJUSTMENTS (3)	DISTRIBUTION AFTER ADJUSTMENT (4)	DISTRIBUTION ADJUSTMENT TO REMOVE PTBAR (5)	DISTRIBUTION AFTER PTBAR ADJUSTMENT (6)	DISTRIBUTION ADJUSTMENT TO REFLECT SFV (7)	DISTRIBUTION AFTER SFV ADJUSTMENT (8)	ALLOCATOR (9)	% (10)
1	Distribution Plant									
2	A360 Land and Land Rights	57,770,583	0	57,770,583	0	57,770,583	0	57,770,583	Direct	
3	A361 Structures and Improvements	20,432,375	0	20,432,375	0	20,432,375	0	20,432,375	Direct	
4	A362 Station Equipment	594,742,798	0	594,742,798	0	594,742,798	0	594,742,798	Direct	
5	A363 Storage Battery Equipment	5,069,926	0	5,069,926	0	5,069,926	0	5,069,926	Direct	
6	A364 Poles,Towers & Fixtures	654,180,595	0	654,180,595	0	654,180,595	0	654,180,595	Direct	
7	A365 O.H. Conductors & Devices	672,468,181	0	672,468,181	0	672,468,181	0	672,468,181	Direct	
8	A366 Underground Conduits	205,104,904	0	205,104,904	0	205,104,904	0	205,104,904	Direct	
9	A367 U.G. Conductors & Devices	567,345,527	0	567,345,527	0	567,345,527	0	567,345,527	Direct	
10	A368 Line Transformers	716,261,529	0	716,261,529	0	716,261,529	0	716,261,529	Direct	
11	A369 Services	315,224,716	0	315,224,716	0	315,224,716	0	315,224,716	Direct	
12	A370 Meters	182,207,258	0	182,207,258	0	182,207,258	0	182,207,258	Direct	
13	A371 Install. on Customer Prem.	54,332,413	0	54,332,413	0	54,332,413	0	54,332,413	Direct	
14	A372 Leased Prop. on Cust. Premises	103,793	0	103,793	0	103,793	0	103,793	Direct	
15	A373 Street Lights	38,739,735	0	38,739,735	0	38,739,735	0	38,739,735	Direct	
16	Total Distribution Plant	4,083,984,333	0	4,083,984,333	0	4,083,984,333	0	4,083,984,333		
17	General Plant									
18	A389 Land and Land Rights	7,896,622	0	7,896,622	0	7,896,622	0	7,896,622	Direct	
19	A390 Structures and Improvements	123,480,728	0	123,480,728	0	123,480,728	0	123,480,728	Direct	
20	A391 Office Furniture & Equip.	4,714,238	0	4,714,238	0	4,714,238	0	4,714,238	Direct	
21	A392 Transportation Equipment	12,731	0	12,731	0	12,731	0	12,731	Direct	
22	A393 Stores Equipment	414,525	0	414,525	0	414,525	0	414,525	Direct	
23	A394 Tools, Shop & Garage Equip.	23,482,002	0	23,482,002	0	23,482,002	0	23,482,002	Direct	
24	A395 Laboratory Equipment	190,418	0	190,418	0	190,418	0	190,418	Direct	
25	A396 Power Operated Equipment	4,943	0	4,943	0	4,943	0	4,943	Direct	
26	A397 Communication Equipment	54,989,338	0	54,989,338	0	54,989,338	0	54,989,338	Direct	
27	A398 Misc. Equipment	2,053,235	0	2,053,235	0	2,053,235	0	2,053,235	Direct	
28	A399 Other Property - Land	0	0	0	0	0	0	0	Direct	
29	A39910 Other Property Land Rights	0	0	0	0	0	0	0	Direct	
30	A39919 ARO General Plant	461,283	0	461,283	0	461,283	0	461,283	Direct	
31	A39930 Other Tangible Property	0	0	0	0	0	0	0	Direct	
32	Total General Plant	217,700,063	0	217,700,063	0	217,700,063	0	217,700,063		
33	Total Electric Plant in Service (101 & 106)	4,383,149,026	0	4,383,149,026	0	4,383,149,026	0	4,383,149,026		
34	Electric Plant Acquisition Adjustment (114)	636,578	0	636,578	0	636,578	0	636,578	Direct	
35	Total Electric Utility Plant	4,383,785,604	0	4,383,785,604	0	4,383,785,604	0	4,383,785,604		

Ohio Power Company - Distribution
Jurisdictional Separation Study
Twelve Months Ended December 31, 2014

Line No.	Description	DISTRIBUTION PER BOOKS	DISTRIBUTION FIXED, KNOWN & MEASURABLE ADJUSTMENTS	DISTRIBUTION AFTER ADJUSTMENT	DISTRIBUTION ADJUSTMENT TO REMOVE PTBAR	DISTRIBUTION AFTER PTBAR ADJUSTMENT	DISTRIBUTION ADJUSTMENT TO REFLECT SFV	DISTRIBUTION AFTER SFV ADJUSTMENT	ALLOCATOR	%
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Accumulated Provision for Depreciation									
2	Steam & Hydraulic	0	0	0	0	0	0	0	N/A	
3	Total Production Plant	0	0	0	0	0	0	0		
4	Transmission	0	0	0	0	0	0	0	N/A	
5	Total Transmission Plant	0	0	0	0	0	0	0		
6	Distribution	(1,454,754,803)	0	(1,454,754 803)	0	(1,454,754,803)	0	(1,454,754,803)	Direct	
7	Total Distribution Plant	(1,454,754,803)	0	(1,454,754 803)	0	(1,454,754,803)	0	(1,454,754,803)		
8	General	(89,220,227)	0	(89,220 227)	0	(89,220,227)	0	(89,220,227)	Direct	
9	Total General Plant	(89,220,227)	0	(89,220 227)	0	(89,220,227)	0	(89,220,227)		
10	Total Accumulated Provision for Depreciation (108)	(1,543,975,030)	0	(1,543,975 030)	0	(1,543,975,030)	0	(1,543,975,030)		
11	Accumulated Provision for Amortization									
12	Intangible	(58,146,872)	0	(58,146,872)	0	(58,146,872)	0	(58,146,872)	Direct	
13	Total Intangible	(58,146,872)	0	(58,146,872)	0	(58,146,872)	0	(58,146,872)		
14	Steam & Hydraulic	0	0	0	0	0	0	0	N/A	
15	Total Production Plant	0	0	0	0	0	0	0		
16	Transmission Plant	0	0	0	0	0	0	0	N/A	
17	Total Transmission Plant	0	0	0	0	0	0	0		
18	Distribution	0	0	0	0	0	0	0		
19	Total Distribution Plant	0	0	0	0	0	0	0		
20	General	(8,986,318)	0	(8,986 318)	0	(8,986,318)	0	(8,986,318)	Direct	
21	Total General Plant	(8,986,318)	0	(8,986 318)	0	(8,986,318)	0	(8,986,318)		
22	Total Accumulated Provision for Amortization (111)	(67,133,190)	0	(67,133,190)	0	(67,133,190)	0	(67,133,190)		
23	Amortization-Plant Acquisition Adjustment (115)	(587,929)	0	(587,929)	0	(587,929)	0	(587,929)	Direct	
24	Total Acc Prov Depreciation and Amortization	(1,611,696,149)	0	(1,611,696,149)	0	(1,611,696,149)	0	(1,611,696,149)		
25	Net Electric Plant in Service	2,772,089,455	0	2,772,089,455	0	2,772,089,455	0	2,772,089,455		
26	Construction Work in Progress (107)	113,868,345	0	113,868,345	0	113,868,345	0	113,868,345	Direct	

Ohio Power Company - Distribution
Jurisdictional Separation Study
Twelve Months Ended December 31, 2014

Line No.	Description	DISTRIBUTION PER BOOKS	DISTRIBUTION FIXED, KNOWN & MEASURABLE ADJUSTMENTS	DISTRIBUTION AFTER ADJUSTMENT	DISTRIBUTION ADJUSTMENT TO REMOVE PTBAR	DISTRIBUTION AFTER PTBAR ADJUSTMENT	DISTRIBUTION ADJUSTMENT TO REFLECT SFV	DISTRIBUTION AFTER SFV ADJUSTMENT	ALLOCATOR	%
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Working Capital Requirements									
2	Assets									
3	Uncollectibles (144)	0	0	0	0	0	0	0	Direct	
4	Fuel Inventory (151, 152)	0	0	0	0	0	0	0	Direct	
5	Materials & Supplies Held for Normal Ops (154, 163)	2,538,347	0	2,538,347	0	2,538,347	0	2,538,347	Direct/Normal Ops	9.01%
6	Prepayments-Other (165)	7,261,648	0	7,261,648	0	7,261,648	0	7,261,648	Direct	
7	Other Current Assets	0	0	0	0	0	0	0	Direct	
8	Total Working Capital Requirements	9,799,995	0	9,799,995	0	9,799,995	0	9,799,995		
9	Other Rate Base Offsets									
10	Customer Deposits (235)	(53,922,061)	0	(53,922,061)	0	(53,922,061)	0	(53,922,061)	Direct	
11	Customer Advances (252)	(250,000)	0	(250,000)	0	(250,000)	0	(250,000)	Direct	
12	Prepayments-Pension (1650010/1650019/1650020)	173,839,011	0	173,839,011	0	173,839,011	0	173,839,011	Direct	
13	Deferred Taxes - Federal (190.1)	122,690,217	0	122,690,217	0	122,690,217	0	122,690,217	Direct	
14	Deferred Taxes - State (190.1)	4,453,049	0	4,453,049	0	4,453,049	0	4,453,049	Direct	
15	Deferred Taxes (281.1)	0	0	0	0	0	0	0	Direct	
16	Deferred Taxes (282.1)	(586,506,790)	0	(586,506,790)	0	(586,506,790)	0	(586,506,790)	Direct	
17	Deferred Taxes - Federal (283.1)	(470,728,955)	0	(470,728,955)	0	(470,728,955)	0	(470,728,955)	Direct	
18	Deferred Taxes - State (283.1)	(24,861,533)	0	(24,861,533)	0	(24,861,533)	0	(24,861,533)	Direct	
19	Deferred Investment Tax Credits (255)	(102,946)	0	(102,946)	0	(102,946)	0	(102,946)	Direct -46(f)(1) portion	
20	Total Other Rate Base Offsets	(835,390,008)	0	(835,390,008)	0	(835,390,008)	0	(835,390,008)		
21	Total Rate Base	2,060,367,786	0	2,060,367,786	0	2,060,367,786	0	2,060,367,786		

Ohio Power Company - Distribution
Jurisdictional Separation Study
Twelve Months Ended December 31, 2014

Line No.	Description	DISTRIBUTION PER BOOKS	DISTRIBUTION FIXED, KNOWN & MEASURABLE ADJUSTMENTS	DISTRIBUTION AFTER ADJUSTMENT	DISTRIBUTION ADJUSTMENT TO REMOVE PTBAR	DISTRIBUTION AFTER PTBAR ADJUSTMENT	DISTRIBUTION ADJUSTMENT TO REFLECT SFV	DISTRIBUTION AFTER SFV ADJUSTMENT	ALLOCATOR	%
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Distribution Firm Sales & Rider Revenue	1,321,964,184	(130,662,245)	1,191,301,939	0	1,191,301,939	26,184,024	1,217,485,964	Specific	100.0%
2	Other Generation and Transmission Revenues	1,519,223,404	(1,519,223,404)	0	0	0	0	0	Specific	100.0%
3	Pilot Throughput Balancing Adjustment Rider	22,989,212	0	22,989,212	(22,989,212)	0	0	0	Specific	100.0%
4	Total Firm Sales	2,864,176,800	(1,649,885,649)	1,214,291,151	(22,989,212)	1,191,301,939	26,184,024	1,217,485,964		
5	Sales for Resale									
6	447 - Sales for Resale	387,387,235	(387,387,235)	0	0	0	0	0		
7	Total Sales for Resale	387,387,235	(387,387,235)	0	0	0	0	0		
8	Other Operating Revenues									
9	450-Forfeited Discounts	3,062,403	0	3,062,403	0	3,062,403	0	3,062,403	Specific	100.0%
10	451-Miscellaneous Service Revenues	7,074,607	0	7,074,607	0	7,074,607	0	7,074,607	Specific	98.3%
11	Subtotal Other Operating Revenues	10,137,010	0	10,137,010	0	10,137,010	0	10,137,010		
12	Rent from Electric Property									
13	4541-Rent-Assoc Cos	4,993,525	(255,290)	4,738,236	0	4,738,236	0	4,738,236		
14	4542-Rent-Non-Assoc Cos	60,230	0	60,230	0	60,230	0	60,230	Specific	4.8%
15	4544-Rent From Elect Prop-ABD-Nonaf	283,945	0	283,945	0	283,945	0	283,945	Specific	32.8%
16	4545-Rent from Elec Prop-Pole Attch	14,862,277	0	14,862,277	0	14,862,277	0	14,862,277	Specific	100.0%
17	Total Rent from Electric Property	20,199,977	(255,290)	19,944,687	0	19,944,687	0	19,944,687		
18	Other Electric Revenue									
19	456-Other Electric Revenue - Distribution	1,203,159	0	1,203,159	0	1,203,159	0	1,203,159	Specific	100.0%
20	456.0015 Other Electric Revenues - ABD	2,589,516	0	2,589,516	0	2,589,516	0	2,589,516	Specific	80.7%
21	456.0041 Misc. Revenue - NonAffiliated	2,300	0	2,300	0	2,300	0	2,300	Specific	91.0%
23	456.0180 Amort of Defer Equity Inc	19,096,848	(19,096,848)	0	0	0	0	0	Specific	100.0%
22	456.1027 PJM Tranms Dist/Meter - NonAff	1,355,652	0	1,355,652	0	1,355,652	0	1,355,652	Specific	100.0%
24	456-Other Electric Revenue - Non-Jurisdictional TCRR	(89,404,764)	89,404,764	0	0	0	0	0	Specific	102.5%
25	456-Other Electric Revenue - Non-Jurisdictional	(2,758,564)	2,758,564	0	0	0	0	0	Specific	-0.9%
26	Total Other Electric Revenues	(67,915,853)	73,066,480	5,150,627	0	5,150,627	0	5,150,627		
27	Total Other Operating Revenues	(37,578,867)	72,811,190	35,232,324	0	35,232,324	0	35,232,324		
28	Total Operating Revenues	3,213,985,168	(1,964,461,693)	1,249,523,475	(22,989,212)	1,226,534,263	26,184,024	1,252,718,287		

Ohio Power Company - Distribution
Jurisdictional Separation Study
Twelve Months Ended December 31, 2014

Line No.	Description	DISTRIBUTION PER BOOKS	DISTRIBUTION FIXED, KNOWN & MEASURABLE ADJUSTMENTS	DISTRIBUTION AFTER ADJUSTMENT	DISTRIBUTION ADJUSTMENT TO REMOVE PTBAR	DISTRIBUTION AFTER PTBAR ADJUSTMENT	DISTRIBUTION ADJUSTMENT TO REFLECT SFV	DISTRIBUTION AFTER SFV ADJUSTMENT	ALLOCATOR	%
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Power Production Expenses									
2	Steam Operation & Maintenance (500-514)	0	0	0	0	0	0	0	N/A	
3	Hydraulic Operations & Maintenance (535-545)	0	0	0	0	0	0	0	N/A	
4	Other Production Operations & Maintenance (546-554)	0	0	0	0	0	0	0	N/A	
5	Subtotal Production Expenses	0	0	0	0	0	0	0		
6	Other Power Supply Expense									
7	555-Purchased Power	1,417,016,841	(1,417,016,841)	0	0	0	0	0	Specific	99.97%
8	555.0110 Purchased Power Discounts	35,716,407	0	35,716,407	0	35,716,407	0	35,716,407	Specific	100.0%
9	556-Sys Control & Load Dispatching	0	0	0	0	0	0	0	N/A	
10	557- Other Expenses	21,635,009	(21,635,009)	0	0	0	0	0	Specific	100.0%
11	Total Other Power Supply Expense	1,474,368,257	(1,438,651,850)	35,716,407	0	35,716,407	0	35,716,407		
12	Total Production O&M Expense	1,474,368,257	(1,438,651,850)	35,716,407	0	35,716,407	0	35,716,407		
13	Transmission Expense									
14	560-Supervision & Engineering	0	0	0	0	0	0	0	N/A	
15	561-Load Dispatching	3,786,658	(3,786,658)	0	0	0	0	0	Specific	38.8%
16	562-Station Equipment	0	0	0	0	0	0	0	N/A	
17	563-Overhead Lines	0	0	0	0	0	0	0	N/A	
18	564-Underground Lines	0	0	0	0	0	0	0	N/A	
19	565-Transmission of Electricity by Others	266,463,122	(266,463,122)	0	0	0	0	0		
20	566-Misc Transmission	0	0	0	0	0	0	0	N/A	
21	567-Rents	0	0	0	0	0	0	0	N/A	
22	575-Regional Market Expenses	2,294,236	(2,294,236)	0	0	0	0	0	Specific	100.0%
23	Total Transmission Operation Expense	272,544,016	(272,544,016)	0	0	0	0	0		
24	568-Supervision & Engineering	0	0	0	0	0	0	0	N/A	
25	569-Structures	0	0	0	0	0	0	0	N/A	
26	570-Station Equipment	0	0	0	0	0	0	0	N/A	
27	571-Overhead Lines	0	0	0	0	0	0	0	N/A	
28	572-Underground Lines	0	0	0	0	0	0	0	N/A	
29	573-Misc Transmission Expenses	0	0	0	0	0	0	0	N/A	
30	Total Transmission Maintenance Expense	0	0	0	0	0	0	0		
31	Total Transmission O&M Expense	272,544,016	(272,544,016)	0	0	0	0	0		

Ohio Power Company - Distribution
Jurisdictional Separation Study
Twelve Months Ended December 31, 2014

Line No.	Description	DISTRIBUTION PER BOOKS	DISTRIBUTION FIXED, KNOWN & MEASURABLE ADJUSTMENTS	DISTRIBUTION AFTER ADJUSTMENT	DISTRIBUTION ADJUSTMENT TO REMOVE PTBAR	DISTRIBUTION AFTER PTBAR ADJUSTMENT	DISTRIBUTION ADJUSTMENT TO REFLECT SFV	DISTRIBUTION AFTER SFV ADJUSTMENT	ALLOCATOR	%
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	Distribution Expense									
2	580-Supervision & Engineering	7,761,729	0	7,761,729	0	7,761,729	0	7,761,729	Specific	100.0%
3	581-Load Dispatching	21,843	0	21,843	0	21,843	0	21,843	Specific	100.0%
4	582-Station Equipment	1,721,942	0	1,721,942	0	1,721,942	0	1,721,942	Specific	100.0%
5	583-Overhead Lines	1,513,688	0	1,513,688	0	1,513,688	0	1,513,688	Specific	100.0%
6	584-Underground Lines	1,512,346	0	1,512,346	0	1,512,346	0	1,512,346	Specific	100.0%
7	585-Street & Area Lighting	161,026	0	161,026	0	161,026	0	161,026	Specific	100.0%
8	586-Meters	1,156,209	0	1,156,209	0	1,156,209	0	1,156,209	Specific	100.0%
9	587-Customer Installations	204,963	0	204,963	0	204,963	0	204,963	Specific	100.0%
10	588.0000 Miscellaneous Distribution Exp	41,874,319	0	41,874,319	0	41,874,319	0	41,874,319	Specific	100.0%
11	588.0004 gSMART-OvUnd Misc Dist Exp	(22,939,208)	0	(22,939,208)	0	(22,939,208)	0	(22,939,208)	Specific	100.0%
12	589.0001 Rents - Nonassociated	5,099,777	0	5,099,777	0	5,099,777	0	5,099,777	Specific	100.0%
13	589.0002 Rents - Associated	333,140	(255,290)	77,850	0	77,850	0	77,850	Specific	100.0%
14	Total Distribution Operation	38,421,774	(255,290)	38,166,484	0	38,166,484	0	38,166,484		
15	590-Supervision & Engineering	539,848	0	539,848	0	539,848	0	539,848	Specific	100.0%
16	591-Structures	81,789	0	81,789	0	81,789	0	81,789	Specific	100.0%
17	592-Station Equipment	5,696,447	0	5,696,447	0	5,696,447	0	5,696,447	Specific	100.0%
18	593.0000 Maintenance of Overhead Lines	124,902,389	0	124,902,389	0	124,902,389	0	124,902,389	Specific	100.0%
19	593.0008 Storm Damage - OvUnd	2,939,426	0	2,939,426	0	2,939,426	0	2,939,426	Specific	100.0%
20	593.0009 ESRR-OvUnd Maint Ovh Lines	332,661	0	332,661	0	332,661	0	332,661	Specific	100.0%
21	593.0010 Storm Expense Amortization	1,090	0	1,090	0	1,090	0	1,090	Specific	100.0%
22	594-Underground Lines	8,878,900	0	8,878,900	0	8,878,900	0	8,878,900	Specific	100.0%
23	595-Line Transformers	2,022,271	0	2,022,271	0	2,022,271	0	2,022,271	Specific	100.0%
24	596-Street & Area Lighting	446,597	0	446,597	0	446,597	0	446,597	Specific	100.0%
25	597-Meters	617,226	0	617,226	0	617,226	0	617,226	Specific	100.0%
26	598-Misc Distribution Plant	3,355,452	0	3,355,452	0	3,355,452	0	3,355,452	Specific	100.0%
27	Total Distribution Maintenance	149,814,096	0	149,814,096	0	149,814,096	0	149,814,096		
28	Total Distribution Expense	188,235,870	(255,290)	187,980,580	0	187,980,580	0	187,980,580		

Ohio Power Company - Distribution
Jurisdictional Separation Study
Twelve Months Ended December 31, 2014

Line No.	Description (1)	DISTRIBUTION PER BOOKS (2)	DISTRIBUTION FIXED, KNOWN & MEASURABLE ADJUSTMENTS (3)	DISTRIBUTION AFTER ADJUSTMENT (4)	DISTRIBUTION ADJUSTMENT TO REMOVE PTBAR (5)	DISTRIBUTION AFTER PTBAR ADJUSTMENT (6)	DISTRIBUTION ADJUSTMENT TO REFLECT SFV (7)	DISTRIBUTION AFTER SFV ADJUSTMENT (8)	ALLOCATOR (9)	% (10)
1	Customer Accounts Expense									
2	901-Supervision & Engineering	1,271,754	0	1,271,754	0	1,271,754	0	1,271,754	Specific	100.0%
3	902-Meter Reading	7,804,086	0	7,804,086	0	7,804,086	0	7,804,086	Specific	100.0%
4	903-Customer Records & Collection Expense	39,422,551	0	39,422,551	0	39,422,551	0	39,422,551	Specific	100.0%
5	904-Uncollectible Accounts	(366,011)	0	(366,011)	0	(366,011)	0	(366,011)	Specific	100.0%
6	904.0002-Uncoll Accts - Pct Income Plan	191,375,823	0	191,375,823	0	191,375,823	0	191,375,823	Specific	100.0%
7	905-Misc Customer Accounts	223,430	0	223,430	0	223,430	0	223,430	Specific	100.0%
8	Total Customer Accounts	239,731,633	0	239,731,633	0	239,731,633	0	239,731,633		
9	Customer Service & Information Expense									
10	907-Supervision	5,612,211	0	5,612,211	0	5,612,211	0	5,612,211	Specific	100.0%
11	908.0000 Customer Assistance Expenses	3,071,080	0	3,071,080	0	3,071,080	0	3,071,080	Specific	100.0%
12	908.0009 Cust Assistance Expense - DSM	67,963,449	(67,963,449)	0	0	0	0	0	Specific	100.0%
13	908.0014 DSM Costs Deferred	3,949,984	(3,949,984)	0	0	0	0	0	Specific	100.0%
14	909-Information & Instruction	0	0	0	0	0	0	0	Specific	100.0%
15	910-Misc Customer Service	292,268	0	292,268	0	292,268	0	292,268	Specific	100.0%
16	Total Customer Service & Information	80,888,992	(71,913,433)	8,975,559	0	8,975,559	0	8,975,559		
17	Sales Expense									
18	911-Supervision	1,783,513	0	1,783,513	0	1,783,513	0	1,783,513	Specific	100.0%
19	912-Demo & Selling	452,861	0	452,861	0	452,861	0	452,861	Specific	100.0%
19	913-Advertising	0	0	0	0	0	0	0	Specific	100.0%
20	916-Misc Sales Expense	0	0	0	0	0	0	0	Specific	100.0%
21	Total Sales Expense	2,236,374	0	2,236,374	0	2,236,374	0	2,236,374		
22	Administrative & General Expense									
23	920-Salaries	28,032,921	0	28,032,921	0	28,032,921	0	28,032,921	Specific	84.7%
24	921-Office Supplies	3,658,638	0	3,658,638	0	3,658,638	0	3,658,638	Specific	91.4%
25	922-Administrative Expense Transferred	(8,846,348)	0	(8,846,348)	0	(8,846,348)	0	(8,846,348)	Specific	99.7%
26	923-Outside Services Employed	6,266,015	0	6,266,015	0	6,266,015	0	6,266,015	Specific	79.2%
27	924-Property Insurance	405,830	0	405,830	0	405,830	0	405,830	Specific	61.0%
28	925-Injuries & Damages	6,195,694	0	6,195,694	0	6,195,694	0	6,195,694	Specific	94.7%
29	926-Employee Pensions and Benefits	13,575,489	0	13,575,489	0	13,575,489	0	13,575,489	Specific	99.8%
30	927-Franchise Requirements	0	0	0	0	0	0	0	Specific	0.0%
31	928-Regulatory Commission Expenses	3,116,403	0	3,116,403	0	3,116,403	0	3,116,403	Specific	99.6%
32	929-Duplicate Charges	0	0	0	0	0	0	0	Specific	0.0%
33	930.1-General Advertising Expense	2,140,085	0	2,140,085	0	2,140,085	0	2,140,085	Specific	99.2%
34	930.2-Misc General Expenses	2,967,260	0	2,967,260	0	2,967,260	0	2,967,260	Specific	70.8%
35	930.2019-gSMART-OvUnd Misc Gen Exp	2,133,288	0	2,133,288	0	2,133,288	0	2,133,288	Specific	100.0%
36	931-Rent	2,143,647	0	2,143,647	0	2,143,647	0	2,143,647	Specific	94.0%
37	Total Admin & General Operation	61,788,920	0	61,788,920	0	61,788,920	0	61,788,920		
38	935-Admin & General Maintenance	13,076,013	0	13,076,013	0	13,076,013	0	13,076,013	Specific	96.1%
39	Total Admin & General Expense	74,864,933	0	74,864,933	0	74,864,933	0	74,864,933		
40	Total Operation & Maint Exp	2,332,870,075	(1,783,364,588)	549,505,487	0	549,505,487	0	549,505,487		

Ohio Power Company - Distribution
Jurisdictional Separation Study
Twelve Months Ended December 31, 2014

Line No.	Description (1)	DISTRIBUTION PER BOOKS (2)	DISTRIBUTION FIXED, KNOWN & MEASURABLE ADJUSTMENTS (3)	DISTRIBUTION AFTER ADJUSTMENT (4)	DISTRIBUTION ADJUSTMENT TO REMOVE PTBAR (5)	DISTRIBUTION AFTER PTBAR ADJUSTMENT (6)	DISTRIBUTION ADJUSTMENT TO REFLECT SFV (7)	DISTRIBUTION AFTER SFV ADJUSTMENT (8)	ALLOCATOR (9)	% (10)
1	4030001 Depreciation Expense									
2	Production	0	0	0	0	0	0	0	N/A	
3	Transmission	0	0	0	0	0	0	0	N/A	
4	Distribution	118,870,055	0	118,870,055	0	118,870,055	0	118,870,055	Direct	
5	General	3,203,481	0	3,203,481	0	3,203,481	0	3,203,481	Direct	
6	Total Depreciation Expense (403)	122,073,535	0	122,073,535	0	122,073,535	0	122,073,535		
7	Amortization Expense									
8	Intangible Plant	15,105,255	0	15,105,255	0	15,105,255	0	15,105,255	Direct	
9	General Plant	146,368	0	146,368	0	146,368	0	146,368	Direct	
10	Total Amortization Expense (404)	15,251,623	0	15,251,623	0	15,251,623	0	15,251,623		
11	Amortization of Plant Acquisition Adjustment	12,696	0	12,696	0	12,696	0	12,696	Specific	100.0%
12	Total Depreciation & Amortization Expense	137,337,855	0	137,337,855	0	137,337,855	0	137,337,855		
13	Reg Debits/Credits Transmission	0	0	0	0	0	0	0	N/A	
14	Reg Debits/Credits Generation	107,272,453	(107,272,453)	0	0	0	0	0	Specific	100.0%
15	Reg Debits/Credits PTBAR	876,914	0	876,914	(876,914)	0	0	0	Specific	100.0%
16	Reg Debits/Credits Storm	2,295,288	0	2,295,288	0	2,295,288	0	2,295,288	Specific	100.0%
17	Reg Debits/Credits DIR	(470,256)	0	(470,256)	0	(470,256)	0	(470,256)	Specific	100.0%
18	Total Reg Debits/Credits (407)	109,974,399	(107,272,453)	2,701,946	(876,914)	1,825,032	0	1,825,032		
1	Other Taxes									
2	Franchise Tax	35,436	0	35,436	0	35,436	0	35,436	Specific	100.3%
3	Commercial Activity Taxes	7,428,608	0	7,428,608	0	7,428,608	0	7,428,608	Specific	99.9%
4	Revenue-kWhr Taxes	146,203,049	0	146,203,049	0	146,203,049	0	146,203,049	Specific	100.0%
5	Payroll Taxes	5,298,864	0	5,298,864	0	5,298,864	0	5,298,864	Specific	104.2%
6	Capacity Taxes	(163,503)	0	(163,503)	0	(163,503)	0	(163,503)	Specific	100.0%
7	Property Taxes	135,389,369	0	135,389,369	0	135,389,369	0	135,389,369	Specific	71.1%
8	Regulatory Fees	4,364,562	0	4,364,562	0	4,364,562	0	4,364,562	Specific	100.0%
9	Production Taxes	0	0	0	0	0	0	0	N/A	
10	Miscellaneous Taxes	2,908	0	2,908	0	2,908	0	2,908	Specific	100.0%
11	Total Taxes Other Than Income (408.1)	298,559,293	0	298,559,293	0	298,559,293	0	298,559,293		
12	Factoring Expense (4265009 & 4265010)	28,809,064	0	28,809,064	0	28,809,064	0	28,809,064	Specific	100.0%
13	431.0002-Interest on Customer Deposits	1,423,124	0	1,423,124	0	1,423,124	0	1,423,124	Specific	100.0%
14	Total Other	30,232,188	0	30,232,188	0	30,232,188	0	30,232,188		
15	State & Local Income Tax (409.1)	(4,868,952)	325,447	(4,543,505)	(206,620)	(4,750,125)	254,771	(4,495,354)	Direct	
16	Deferred State Income Tax (410.1 & 411.1)	16,658,726	(1,043,761)	15,614,965	(8,532)	15,606,433	0	15,606,433	Direct	
17	Total State Income Taxes	11,789,774	(718,314)	11,071,460	(215,152)	10,856,308	254,771	11,111,079		
18	Current Federal Income Taxes (409.1)	38,407,932	11,592,824	50,000,756	(7,360,067)	42,640,689	9,075,239	51,715,928	Direct	
19	Deferred Federal Income Tax (410.1 & 411.1)	30,761,505	(37,180,042)	(6,418,537)	(303,934)	(6,722,471)	0	(6,722,471)	Direct	
20	Deferred Investment Tax Credit (411.4)	(92,654)	0	(92,654)	0	(92,654)	0	(92,654)	Direct	
21	Total Federal Income Taxes	69,076,784	(25,587,218)	43,489,566	(7,664,001)	35,825,565	9,075,239	44,900,804		

AEP Ohio
Straight Fixed Variable Revenue Adjustment Calculation

Rate Zone	Tariff Class	2014 Bill Counts	Straight Fixed-Variable Rate	Straight Fixed Variable Base Revenues	2014 Base Revenues	Revenue Adjustment	PTBAR 2014 Accrual	Difference from PTBAR 2014 Accrual
OP	RS	7,209,954	$27.24	$196,399,147	$178,827,067	$17,572,080		
OP	RS-TOD	3,768	$28.09	$105,843	$122,906	-$17,063		
OP	Total Residential	7,213,722		$196,504,990	$178,949,974	$17,555,016	$7,636,364	$9,918,652
CSP	R-R	5,987,465	$27.24	$163,098,547	$180,003,053	-$16,904,506		
CSP	R-R-1	2,072,817	$27.24	$56,463,535	$31,188,212	$25,275,323		
CSP	RLM	491	$27.74	$13,620	$34,952	-$21,332		
CSP	RS-TOD	106	$28.09	$2,978	$2,450	$527		
CSP	RS-TOD2	17,516	$27.24	$477,136	$489,795	-$12,659		
CSP	RS-CPP	1,972	$27.24	$53,717	$57,643	-$3,926		
CSP	RS-RTP	95	$27.24	$2,588	$2,848	-$260		
CSP	Total Residential	8,080,462		$220,112,120	$211,778,953	$8,333,167	$13,572,227	-$5,239,060
AEP Ohio	Total Residential	15,294,184		$416,617,111	$390,728,927	$25,888,184	$21,208,591	$4,679,593
OP	GS-1	787,383	$14.81	$11,661,142	$11,403,986	$257,156		
OP	GS-1 On-Peak	95	$15.66	$1,488	$1,674	-$186		
OP	GS-1 Unmetered	7,771	$13.26	$103,043	$62,521	$40,522		
OP	Flood Pumps	312	$14.81	$4,621	$9,887	-$5,266		
OP	Total GS-1	795,561		$11,770,294	$11,478,068	$292,226	$41,342	$250,884
CSP	GS-1	624,020	$14.81	$9,241,736	$9,013,538	$228,198		
CSP	GS-1 Unmetered	7,083	$13.26	$93,921	$318,504	-$224,583		
CSP	Total GS-1	631,103		$9,335,657	$9,332,042	$3,614	$222,364	-$218,750
AEP Ohio	Total GS-1	1,426,664		$21,105,951	$20,810,110	$295,841	$263,706	$32,135
AEP Ohio Total Adjustment				$437,723,061	$411,539,037	$26,184,024	$21,472,297	$4,711,727

PLC-2 014

AEP Ohio
Straight Fixed Variable Rate Design

Rate Zone	Tariff Class	11-351 & 11-352 Bill Counts	11-351 & 11-352 Current Base Revenues	11-351 & 11-352 Meter Cost Differential	Revenues from Meter Cost Differential	Revenue Requirement after Meter Differential	Straight Fixed Variable Rate	Verification	Rate Design Difference
OP	RS	7,207,281	$187,509,197	$0.00	$0		$27.24	$196,326,334	
OP	RS-TOD	4,902	$169,213	$0.85	$4,167		$28.09	$137,697	
OP	Total Residential	7,212,183	$187,678,410		$4,167			$196,464,032	
CSP	R-R	5,627,434	$188,578,113	$0.00	$0		$27.24	$153,291,302	
CSP	R-R-1	2,218,108	$33,867,584	$0.00	$0		$27.24	$60,421,262	
CSP	RLM	846	$71,669	$0.50	$423		$27.74	$23,468	
CSP	RS-ES	24	$590	$0.85	$20		$28.09	$674	
CSP	RS-TOD	76	$1,737	$0.85	$65		$28.09	$2,135	
CSP	Total Residential	7,846,488	$222,519,694		$508			$213,738,841	
AEP Ohio	Total Residential	15,058,671	$410,198,104		$4,675	$410,193,430		$410,202,873	-$4,769
OP	GS-1	778,125	$11,307,455	$0.00	$0		$14.81	$11,524,031	
OP	GS-1 On-Peak	263	$5,452	$0.85	$224		$15.66	$4,119	
OP	GS-1 Unmetered	8,193	$67,010	-$1.55	-$12,699		$13.26	$108,639	
OP	Flood Pumps	312	$9,262	$0.00	$0		$14.81	$4,621	
OP	Total GS-1	786,893	$11,389,179		-$12,476			$11,641,410	
CSP	GS-1	614,678	$9,071,468	$0.00	$0		$14.81	$9,103,381	
CSP	GS-1 Unmetered	7,319	$381,610	-$1.55	-$11,344		$13.26	$97,050	
CSP	Total GS-1	621,997	$9,453,078		-$11,344			$9,200,431	
AEP Ohio	Total GS-1	1,408,890	$20,842,257		-$23,820	$20,866,077		$20,841,841	$416

OHIO POWER COMPANY
CLASS COST-OF-SERVICE STUDY - CUSTOMER CHARGE
TWELVE MONTHS ENDING MAY 31, 2011

Data: 3 MOS Actual & 9 MOS Estimated
Type of Filing: >Original__Updated__Revised
Work Paper Reference No(s): WP A-1e-p and all Schedule E3.2 Work Papers

Schedule E-3.1
Page 1 of 6
Witness Responsible:
Daniel E. High

Label	Allocation Factor	Function	Total Retail	RS	GS-1	SEC	PRI	SUB/TRAN	OL	SL
Rate Base										
Plant in Service										
Distribution										
360 Land and Land Rights	DIST_CPD	TOTAL	-	-	-	-	-	-	-	-
361 Structures and Improvements	DIST_CPD	TOTAL	-	-	-	-	-	-	-	-
362 Station Equipment	DIST_CPD	TOTAL	-	-	-	-	-	-	-	-
363 Storage Battery Equipment	DIST_CPD	TOTAL	-	-	-	-	-	-	-	-
364 Poles, Towers & Fixtures	DIST_POLES	TOTAL	-	-	-	-	-	-	-	-
365 Overhead Lines	DIST_OHLINES	TOTAL	-	-	-	-	-	-	-	-
366 Underground Conduit	DIST_UGLINES	TOTAL	-	-	-	-	-	-	-	-
367 Underground Lines	DIST_UGLINES	TOTAL	-	-	-	-	-	-	-	-
368 Transformers	DIST_TRANSF	TOTAL	-	-	-	-	-	-	-	-
369 Services	DIST_SERV	TOTAL	135,157,954	106,525,465	11,519,258	6,102,533	-	-	10,834,152	176,546
370 Meters	DIST_METERS	TOTAL	70,138,185	39,848,665	6,371,020	16,971,615	2,493,786	4,453,099	-	-
371 Install on Cust. Premises	DIST_OL	TOTAL	22,791,009	-	-	-	-	-	22,791,009	-
372 Leased Prop. On Cust. Premises	DIST_OL	TOTAL	1,104	-	-	-	-	-	1,104	-
373 Street Lighting	DIST_SL	TOTAL	21,232,932	-	-	-	-	-	-	21,232,932
Total		TOTAL	249,321,184	146,374,130	17,890,278	23,074,148	2,493,786	4,453,099	33,626,265	21,409,478
Total Plant in Service		TOTAL	249,321,184	146,374,130	17,890,278	23,074,148	2,493,786	4,453,099	33,626,265	21,409,478
General Plant	LABOR_M	TOTAL	32,629,866	24,016,177	2,272,437	2,128,672	167,732	839,436	2,296,881	908,531
Intangible Plant	LABOR_M	TOTAL	7,482,064	5,506,936	521,072	488,107	38,461	192,484	526,677	208,327
Total General & Intangible Plant		TOTAL	40,111,930	29,523,113	2,793,509	2,616,779	206,194	1,031,919	2,823,558	1,116,858
Total Electric Plant in Service		TOTAL	289,433,114	175,897,243	20,683,787	25,690,928	2,699,979	5,485,018	36,449,823	22,526,336
Electric Plant Acquisition Adj. - Account 302	LABOR_M	TOTAL	192,123	141,406	13,380	12,534	988	4,943	13,524	5,349
Electric Utility Plant		TOTAL	289,625,237	176,038,649	20,697,167	25,703,461	2,700,967	5,489,961	36,463,347	22,531,685
Accum. Depreciation and Amortiz.										
Distribution	RB_GUP_EPIS_D	TOTAL	(81,621,472)	(47,919,201)	(5,856,826)	(7,553,895)	(816,403)	(1,457,832)	(11,008,392)	(7,008,924)
General & Intangible	RB_GUP_EPIS_G	TOTAL	(21,399,689)	(15,750,562)	(1,490,335)	(1,396,050)	(110,004)	(550,528)	(1,506,366)	(595,843)
Total		TOTAL	(103,021,161)	(63,669,763)	(7,347,161)	(8,949,945)	(926,407)	(2,008,361)	(12,514,758)	(7,604,766)
Amortiz. Of Plant Acquisition Adj. - Acct 302	LABOR_M	TOTAL	(160,836)	(118,379)	(11,201)	(10,492)	(827)	(4,138)	(11,322)	(4,478)
Net Electric Plant In Service		TOTAL	186,443,240	112,250,508	13,338,804	16,743,024	1,773,734	3,477,462	23,937,267	14,922,441
Working Capital										
Uncollectibles	RSALE	TOTAL	-	-	-	-	-	-	-	-
Materials & Supplies - Dist	RB_GUP_EPIS_D	TOTAL	1,040,534	610,888	74,665	96,299	10,408	18,585	140,338	89,352
Prepayments - Other (Insurance, etc.)	RB_GUP	TOTAL	293,729	178,533	20,990	26,068	2,739	5,588	36,980	22,851
Other Current Assets	LABOR_M	TOTAL	-	-	-	-	-	-	-	-
Total Working Capital		TOTAL	1,334,263	789,421	95,655	122,367	13,147	24,153	177,318	112,203

Rate Base Offsets

OHIO POWER COMPANY
CLASS COST-OF-SERVICE STUDY - CUSTOMER CHARGE
TWELVE MONTHS ENDING MAY 31, 2011

Data: 3 MOS Actual & 9 MOS Estimated
Type of Filing: >Original__Updated__Revised
Work Paper Reference No(s): WP A-1e-p and all Schedule E3.2 Work Papers

Schedule E-3.1

Witness Responsible:
Daniel E. High

Label	Allocation Factor	Function	Total Retail	RS	GS-1	SEC	PRI	SUB/TRAN	OL	SL
Customer Deposits	CUST_DEP	TOTAL	(26,468,865)	(16,034,032)	(807,800)	(4,982,051)	(919,359)	(3,694,937)	(30,687)	-
Customer Advances	RB_GUP_EPIS_D	TOTAL	-	-	-	-	-	-	-	-
Prepayments - Pension	LABOR_M	TOTAL	20,670,064	15,213,545	1,439,522	1,348,452	106,254	531,758	1,455,007	575,527
Deferred Taxes (190.1)	RB_GUP_EPIS_D	TOTAL	6,883,525	4,041,253	493,934	637,056	68,851	122,946	928,390	591,096
Deferred Taxes (281.1)	RB_GUP_EPIS_D	TOTAL	-	-	-	-	-	-	-	-
Deferred Taxes (282.1)	RB_GUP_EPIS_D	TOTAL	(23,622,075)	(13,888,299)	(1,695,024)	(2,168,173)	(238,275)	(421,911)	(3,185,939)	(2,028,453)
Deferred Taxes (283.1)	RB_GUP_EPIS_D	TOTAL	(10,057,800)	(5,904,840)	(721,707)	(930,828)	(100,601)	(179,641)	(1,356,508)	(863,674)
Deferred Taxes - State (283.1)	RB_GUP_EPIS_D	TOTAL	(173,313)	(101,750)	(12,436)	(16,040)	(1,734)	(3,096)	(23,375)	(14,883)
Deferred Investment Tax Credits (255)	RB_GUP_EPIS_D	TOTAL	(77,000)	(45,208)	(5,525)	(7,126)	(770)	(1,375)	(10,385)	(6,612)
Total		TOTAL	(32,845,463)	(16,699,329)	(1,309,037)	(6,136,710)	(1,083,634)	(3,646,256)	(2,223,498)	(1,746,999)
Total Rate Base		TOTAL	154,932,039	86,340,599	12,125,422	10,728,681	703,246	(144,841)	21,891,088	13,287,645
Operating Revenues										
Firm Sales of Electricity	RSALE	TOTAL	95,291,817	54,775,152	5,614,276	5,057,830	460,138	21,095,729	4,767,475	3,521,221
Other Operating Revenues										
Forfeited Discounts	FORF_DISC	TOTAL	207,781	11,692	145,969	54,849	2,403	(7,165)	31	1
Miscellaneous Service Revenue	MISC_SERV_REV	TOTAL	437,206	396,945	28,675	4,214	15	20	5,926	1,412
Rent Assoc Co	RB_GUP_EPIS_D	TOTAL	603,247	354,161	43,287	55,829	6,034	10,775	81,361	51,801
Rent Non-Assoc Co	RB_GUP_EPIS_D	TOTAL	1,110,985	652,249	79,720	102,819	11,112	19,843	149,840	95,402
Rent ABD	RB_GUP_EPIS_D	TOTAL	10,347	6,076	742	958	103	185	1,396	889
Other Electric Revenue-NonAff	RB_GUP_EPIS_D	TOTAL	363,012	213,121	26,048	33,596	3,631	6,484	48,960	31,172
Other Electric Revenue - ABD	RB_GUP_EPIS_D	TOTAL	239,347	140,516	17,175	22,151	2,394	4,275	32,281	20,553
Other Electric Rev. - PJM Trans Dist/Meter	RB_GUP_EPIS_D	TOTAL	128,162	75,254	9,198	11,863	1,282	2,289	17,288	11,007
Total - Other Operating Revenues		TOTAL	3,100,108	1,850,015	350,814	286,279	26,974	36,706	337,082	212,237
Total Operating Revenues		TOTAL	98,391,925	56,625,167	5,965,090	5,344,109	487,112	21,132,435	5,104,557	3,733,458
Operating Expense										
O&M Expense										
Distribution Operation										
580 Supervision & Engineering	TOTOXEXP	TOTAL	696,102	397,903	52,314	88,949	11,244	20,056	66,634	59,002
581 Load Dispatching	DIST_CPD	TOTAL	-	-	-	-	-	-	-	-
582 Station Equipment	DIST_CPD	TOTAL	-	-	-	-	-	-	-	-
583 Overhead Lines	DIST_OHLINES	TOTAL	-	-	-	-	-	-	-	-
584 Undergroung Lines	DIST_UGLINES	TOTAL	-	-	-	-	-	-	-	-
585 Street Lighting	DIST_SL	TOTAL	130,576	-	-	-	-	-	-	130,576
586 Meters	DIST_METERS	TOTAL	1,355,619	770,188	123,138	328,025	48,199	86,069	-	-
587 Customer Installations	DIST_PCUST	TOTAL	104,068	81,949	8,862	4,695	92	-	8,335	136
588 Miscellaneous Distribution	RB_GUP_EPIS_D	TOTAL	3,198,173	1,877,817	229,488	295,984	31,989	57,122	431,342	274,831
589 Rents	RB_GUP_EPIS_D	TOTAL	477,601	280,395	34,271	44,201	4,777	8,530	64,415	41,012
Total		TOTAL	5,962,139	3,408,053	448,073	761,854	96,301	171,777	570,725	505,357
Distribution Maintenance										
590 Supervision & Engineering	TOTMXEXP	TOTAL	32,066	3,503	560	1,492	219	391	21,879	4,021
591 Structures	DIST_CPD	TOTAL	-	-	-	-	-	-	-	-
592 Station Equipment	DIST_CPD	TOTAL	-	-	-	-	-	-	-	-
593 Overhead Lines	TOTOHLINES	TOTAL	-	-	-	-	-	-	-	-
594 Underground Lines	TOTUGLINES	TOTAL	-	-	-	-	-	-	-	-

OHIO POWER COMPANY
CLASS COST-OF-SERVICE STUDY - CUSTOMER CHARGE
TWELVE MONTHS ENDING MAY 31, 2011

Data: 3 MOS Actual & 9 MOS Estimated
Type of Filing: >Original__Updated__Revised
Work Paper Reference No(s): WP A-1e-p and all Schedule E3.2 Work Papers

Schedule E-3.1
Page 3 of 6
Witness Responsible:
Daniel E. High

Label	Allocation Factor	Function	Total Retail	RS	GS-1	SEC	PRI	SUB/TRAN	OL	SL
595 Line Transformers	DIST_TRANSF	TOTAL	-	-	-	-	-	-	-	-
596 Street Lighting	DIST_SL	TOTAL	291,693	-	-	-	-	-	-	291,693
597 Meters	DIST_METERS	TOTAL	447,298	254,130	40,630	108,234	15,904	28,399	-	-
598 Miscellaneous Distribution	DIST_OL	TOTAL	1,587,332	-	-	-	-	-	1,587,332	-
Total		TOTAL	2,358,389	257,633	41,190	109,726	16,123	28,791	1,609,211	295,714
Customer Accounts										
901 Supervision & Engineering	TOTOX234	TOTAL	1,236,517	1,080,747	94,360	58,685	1,242	309	43	1,131
902 Meter Reading	CUST_902	TOTAL	4,971,654	4,119,497	445,467	394,262	9,820	2,609	-	-
903 Customer Records & Collection Exp.	CUST_903	TOTAL	19,708,498	17,453,402	1,437,934	776,771	14,911	3,442	-	22,038
904 Uncollectible Accounts	UNCOLFAC	TOTAL	6,342	3,723	455	587	63	113	855	545
Factoring Expense	RSALE	TOTAL	3,007,437	1,728,719	177,188	159,627	14,522	665,787	150,463	111,131
431-Interest on Customer Deposits	CUST_DEP	TOTAL	793,231	480,515	24,209	149,304	27,552	110,732	920	-
905 Miscellaneous Customer Accounts	TOTOX234	TOTAL	73,207	63,985	5,587	3,474	74	18	3	67
Total		TOTAL	29,796,885	24,930,589	2,185,199	1,542,710	68,184	783,010	152,283	134,911
Customer Service & Inf & Sales Exp										
907 Supervision	EXP_OM_CUSTACCT	TOTAL	1,074,267	898,822	78,783	55,619	2,458	28,230	5,490	4,864
908 Customer Assistance	EXP_OM_CUSTACCT	TOTAL	1,287,487	1,077,221	94,420	66,659	2,946	33,833	6,580	5,829
909 Information & Instruction	EXP_OM_CUSTACCT	TOTAL	295,991	247,651	21,707	15,325	677	7,776	1,513	1,340
910 Miscellaneous Customer Service	EXP_OM_CUSTACCT	TOTAL	1,776	1,486	130	92	4	47	9	8
911-916 Misc Selling Expense	EXP_OM_CUSTACCT	TOTAL	9,607	8,038	705	497	22	252	49	43
Total		TOTAL	2,669,128	2,233,218	195,744	138,192	6,108	70,140	13,841	12,085
Administrative & General Expense										
920-Salaries	LABOR_M	TOTAL	2,459,015	1,809,880	171,253	160,419	12,640	63,261	173,095	68,468
921-Office Supplies	LABOR_M	TOTAL	246,061	181,098	17,136	16,052	1,265	6,330	17,320	6,851
922-Admin Exp Transferred	LABOR_M	TOTAL	(973,026)	(716,165)	(67,764)	(63,477)	(5,002)	(25,032)	(68,493)	(27,092)
923.0001 Outside Svcs Empl - Non-Assoc.	LABOR_M	TOTAL	375,253	276,193	26,134	24,480	1,929	9,654	26,415	10,448
923.0003 AEPSC Billed to Client Co.	LABOR_M	TOTAL	2,480,673	1,825,820	172,761	161,831	12,752	63,818	174,619	69,071
924-Property Insurance	RB_GUP_EPIS_D	TOTAL	40,027	23,500	2,872	3,704	400	715	5,399	3,437
925-Injuries & Damages	LABOR_M	TOTAL	592,185	435,859	41,241	38,632	3,044	15,235	41,685	16,489
926.0000 OPEB - Employee Benefits	LABOR_M	TOTAL	2,114,752	1,556,498	147,277	137,960	10,871	54,404	148,862	58,882
926.0003 Pension Plan	LABOR_M	TOTAL	648,112	477,022	45,136	42,281	3,332	16,673	45,622	18,046
927-Franchise Requirements	RSALE	TOTAL	-	-	-	-	-	-	-	-
9280000 Reg. Commission Exp.	RSALE	TOTAL	28,347	16,294	1,670	1,505	137	6,275	1,418	1,047
929 Duplicate Charges	LABOR_M	TOTAL	-	-	-	-	-	-	-	-
930.1 Gen. Advertising Exp.	LABOR_M	TOTAL	278,555	205,021	19,399	18,172	1,432	7,166	19,608	7,756
930.2000 Misc. General Expenses	LABOR_M	TOTAL	629,754	463,511	43,858	41,083	3,237	16,201	44,330	17,535
930.2007 ABD Exp.	RB_GUP_EPIS_D	TOTAL	71,052	41,714	5,098	6,576	711	1,269	9,583	6,101
931 Rent	LABOR_M	TOTAL	337,341	248,289	23,493	22,007	1,734	8,678	23,746	9,393
935 A&G - Maintenance	LABOR_M	TOTAL	1,258,111	925,992	87,618	82,075	6,467	32,366	88,561	35,030
Total		TOTAL	10,586,202	7,770,525	737,184	693,300	54,949	277,013	751,769	301,481
Total O&M Expense		TOTAL	51,372,743	38,600,018	3,607,390	3,245,782	241,665	1,330,730	3,097,630	1,249,528
Depreciation & Amortization Expense										
Distribution	RB_GUP_EPIS_D	TOTAL	9,294,156	5,456,512	666,911	860,154	92,963	166,002	1,253,515	798,099
General & Intangible	RB_GUP_EPIS_G	TOTAL	1,890,244	1,391,254	131,642	123,314	9,717	48,628	133,058	52,631
Total Depreciation & Amort Expense		TOTAL	11,184,400	6,847,766	798,553	983,468	102,680	214,630	1,386,573	850,730

OHIO POWER COMPANY
CLASS COST-OF-SERVICE STUDY - CUSTOMER CHARGE
TWELVE MONTHS ENDING MAY 31, 2011

Data: 3 MOS Actual & 9 MOS Estimated
Type of Filing: >Original__Updated__Revised
Work Paper Reference No(s): WP A-1e-p and all Schedule E3.2 Work Papers

Witness Responsible:
Daniel E. High

Label	Allocation Factor	Function	Total Retail	RS	GS-1	SEC	PRI	SUB/TRAN	OL	SL
Taxes Other Than Income										
Payroll Taxes	LABOR_M	TOTAL	732,811	639,362	51,035	47,808	3,767	18,852	51,584	20,404
Commercial Activity Taxes	RSALE	TOTAL	1,314,864	755,803	77,487	69,789	6,349	291,085	65,783	46,587
Property Taxes	NP	TOTAL	8,960,269	5,394,855	641,051	804,654	85,244	167,124	1,150,403	717,159
Regulatory Fees	RSALE	TOTAL	816,882	469,556	48,128	43,358	3,944	180,841	40,869	30,185
Franchise Tax	RSALE	TOTAL	38,330	22,033	2,258	2,034	185	8,486	1,918	1,416
Miscellaneous Taxes	NP	TOTAL	(1,183)	(712)	(85)	(106)	(11)	(22)	(152)	(95)
Total Taxes Other Than Income		TOTAL	11,861,992	7,180,896	819,855	967,536	99,478	668,366	1,310,404	817,657
Total Operating Expense Before Income Tax		TOTAL	74,419,136	52,628,481	5,225,797	5,196,787	443,823	2,211,726	5,794,607	2,917,914
Gross Operating Income		TOTAL	23,972,790	3,996,666	739,293	147,322	43,289	18,920,709	(690,050)	815,544
Interest Expense Factor										
Interest Expense Synchronized		TOTAL	3,752,764	2,333,562	293,702	259,870	17,034	(3,504)	530,246	321,853
Net Operating Income Before Income Tax		TOTAL	20,220,026	1,663,124	445,591	(112,548)	26,255	18,924,212	(1,220,296)	493,690
Schedule M Income Adjustments										
Labor Related	LABOR_M	TOTAL	(3,357,600)	(2,471,255)	(233,833)	(219,040)	(17,260)	(86,378)	(236,348)	(93,487)
Rate Base Related	RATEBASE	TOTAL	(50,806)	(31,592)	(3,976)	(3,518)	(231)	47	(7,179)	(4,357)
Distribution Plant Related	RB_GUP_EPIS_D	TOTAL	(5,584,448)	(3,278,577)	(400,717)	(516,829)	(55,857)	(99,743)	(753,182)	(479,543)
General Plant Related	RB_GUP_EPIS_D	TOTAL	35,706	20,963	2,562	3,305	357	638	4,816	3,066
Total Schedule M Income Adjustments		TOTAL	(8,957,148)	(5,760,462)	(635,964)	(736,082)	(72,990)	(185,436)	(991,893)	(574,321)
State Tax Adjustments										
Illinois - Plant Related	RB_GUP_EPIS_D	TOTAL	1,932,755	1,134,702	138,687	178,872	19,332	34,521	260,673	165,968
Michigan - Plant Related	RB_GUP_EPIS_D	TOTAL	2,339,352	1,373,411	167,862	216,502	23,399	41,783	315,511	200,883
Ohio - Plant Related	RB_GUP_EPIS_D	TOTAL	678,014	398,056	48,652	62,749	6,782	12,110	91,445	58,222
West Virginia - Plant Related	RB_GUP_EPIS_D	TOTAL	-	-	-	-	-	-	-	-
Illinois Taxable Income		TOTAL	13,195,633	(2,962,635)	(51,687)	(669,757)	(27,403)	18,773,297	(1,951,515)	85,337
Tax Factor (Tax Rate x Apportionment)										
Illinois Tax		TOTAL	7,694	(1,727)	(30)	(391)	(16)	10,946	(1,138)	50
Michigan Taxable Income		TOTAL	13,802,229	(2,723,926)	(22,511)	(632,128)	(23,337)	18,780,559	(1,896,677)	120,252
Tax Factor (Tax Rate x Apportionment)										
Michigan Tax		TOTAL	4,167	(834)	(7)	(194)	(7)	5,753	(581)	37
Ohio Municipal Taxable Income		TOTAL	11,940,692	(3,699,262)	(141,722)	(785,881)	(39,954)	18,750,887	(2,120,744)	(22,409)
Tax Factor (Tax Rate x Apportionment)										
Ohio Tax		TOTAL	42,049	(13,027)	(499)	(2,767)	(141)	66,030	(7,468)	(79)
West Virginia Taxable Income		TOTAL	11,262,878	(4,097,338)	(190,373)	(848,830)	(48,735)	18,738,777	(2,212,188)	(80,631)
Tax Factor (Tax Rate x Apportionment)										
West Virginia Tax		TOTAL	148,546	(54,040)	(2,511)	(11,193)	(616)	247,146	(29,177)	(1,063)

Data: 3 MOS Actual & 9 MOS Estimated
Type of Filing: >Original__Updated__Revised
Work Paper Reference No(s): WP A-1e-p and all Schedule E3.2 Work Papers

Label	Allocation Factor	Function	Total Retail	RS	GS-1	SEC	PRI	SUB/TRAN	OL	SL
Deferred State Income Tax (410.1 & 411.1)	RB_GUP_EPIS_D	TOTAL	19,054	11,187	1,367	1,763	191	340	2,570	1,636
Total State Income Tax		TOTAL	221,510	(58,442)	(1,680)	(12,781)	(590)	330,215	(35,794)	580
Federal Taxable Income		TOTAL	11,060,422	(4,027,709)	(187,326)	(834,086)	(45,955)	18,408,902	(2,173,825)	(79,575)
Tax Factor (Tax Rate x Apportionment)										
Gross Current FIT		TOTAL	3,871,148	(1,409,698)	(65,564)	(291,930)	(16,084)	6,443,116	(760,839)	(27,851)
Deferred FIT										
DFIT (410.1 & 411.1)	RB_GUP_EPIS_D	TOTAL	2,491,005	1,462,446	178,744	230,537	24,916	44,492	335,965	213,905
Deferred ITC										
Investment Tax Credit (411.4 & 411.5)	RB_GUP_EPIS_D	TOTAL	-	-	-	-	-	-	-	-
Total Federal Income Tax		TOTAL	6,362,153	52,748	113,180	(61,393)	8,831	6,487,607	(424,874)	186,054
Total Income Tax		TOTAL	6,583,663	(5,694)	111,501	(74,173)	8,242	6,817,822	(460,667)	186,634
Total Expenses		TOTAL	81,002,798	52,622,787	5,337,298	5,122,813	452,065	9,029,549	5,333,940	3,104,549
Net Operating Income		TOTAL	17,389,127	4,002,380	627,792	221,496	35,047	12,102,888	(229,383)	628,909
Current Rate of Return			4.72%	4.15%	5.18%	2.16%	4.14%	-8367.52%	-1.05%	4.73%
O&M Labor										
Distribution	EXP_OM_DIST	TOTAL	3,867,413	1,703,825	227,411	405,114	52,255	93,225	1,013,243	372,341
Customer Accounts	EXP_OM_CUSTACCT	TOTAL	9,191,787	7,690,625	674,093	475,897	21,034	241,544	46,977	41,618
Customer Service	EXP_OM_CUSTSERV	TOTAL	2,159,217	1,806,583	158,349	111,792	4,941	56,740	11,035	9,776
Total		TOTAL	15,218,417	11,201,033	1,059,854	992,803	78,230	391,509	1,071,254	423,734
Calculation of Proposed Revenues										
Proposed Operating Income (NOI + Inc. Defic.)	RATEBASE	TOTAL	13,063,936	8,123,481	1,022,421	904,647	59,298	(12,196)	1,845,866	1,120,420
Proposed Rate of Return			8.43%	8.43%	8.43%	8.43%	8.43%	8.43%	8.43%	8.43%
Income Increase		TOTAL	(4,325,191)	4,121,100	394,628	683,151	24,251	(12,115,083)	2,075,248	491,511
Gross Revenue Conversion Factor										
Total Revenue Increase		TOTAL	(6,818,594)	6,496,848	622,125	1,076,977	38,231	(19,099,233)	3,271,596	774,859
Less: Miscellaneous Service Charge Increases	MISC_SERV_REV	TOTAL	68,531	62,220	4,495	660	2	3	929	221
Less: Pole Attachment Increases	RB_GUP_EPIS_D	TOTAL	196,630	115,440	14,109	18,198	1,967	3,512	28,520	16,886
Proposed Sales Revenue Increase		TOTAL	(7,083,755)	6,319,189	603,521	1,058,119	36,262	(19,102,748)	3,244,147	757,752
Total Proposed Sales Revenue		TOTAL	88,208,063	61,094,341	6,217,798	6,115,948	496,400	1,992,981	8,011,622	4,278,974

OHIO POWER COMPANY
CLASS COST-OF-SERVICE STUDY - CUSTOMER CHARGE
TWELVE MONTHS ENDING MAY 31, 2011

Data: 3 MOS Actual & 9 MOS Estimated
Type of Filing: >Original__Updated__Revised
Work Paper Reference No(s): WP A-1e-p and all Schedule E3.2 Work Papers

Witness Responsible:
Daniel E. High

Label	Allocation Factor	Function	Total Retail	RS	GS-1	SEC	PRI	SUB/TRAN	OL	SL
Customer Bills				7,212,183	786,893	423,494	8,142	1,916		
Full Cost Customer Charge				8.47	7.90	14.44	60.97	1,040.18		

Source: WP A-1e-p and all Schedule E-3.2 Work Papers

Date Prepared: 2/28/2011

OHIO POWER COMPANY'S RESPONSE
TO NATURAL RESOURCES DEFENSE COUNCIL'S
DISCOVERY REQUEST
PUCO CASE NO. 16-1852-EL-SSO
FIRST SET

INTERROGATORY

NRDC-INT-1-001 On page 13, lines 3-4, of Witness Moore's Direct Testimony, Witness Moore states, "that a full customer charge should be $27.24 for a standard residential customer." Please answer the following questions regarding that statement.

A. Please explain whether the stated charge is based on embedded or marginal cost principles.

B. Please disaggregate the "full customer charge" in the greatest detail available, including, at a minimum, the following: the meter cost, meter-reading cost, billing, service drop, customer service, and any other identifiable cost components.

C. Please explain whether the estimate of customer costs included in the $27.24 is based on the smallest residential customer, the average single-family residential customer, the average multi-family residential customer, the average residential customer, or some other customer group.

D. Please explain whether the estimate of service-drop costs included in the $27.24 estimate of customer costs assumes that the customer has a dedicated service drop, or is in a multi-family building that shares a service drop among several customers.

RESPONSE

A. The $27.24 full customer charge identified in Company witness Moore's testimony reflects the embedded costs of serving AEP Ohio residential customers.

B. See NRDC-RPD-1-001 Attachment 1.

C. The $27.24 represents the average base revenue per residential bill. The residential base revenues that support the $27.24 were presented in the presented in Column K of Schedule E-4.1 in Case Nos. 11-351-EL-AIR and 11-352-EL-AIR and were calculated using base rates at the time of that filing. The total number of residential bills issued during the test period are presented in Column C of the same schedules.

D. The Company does not allocate service drop assets, included in FERC Account 369 Services, to a level lower than the customer classes identified in Class Cost-of-Service Studies developed by Company witness High in Case Nos. 11-351-EL-AIR and 11-352-EL-AIR.

Prepared by: Andrea E. Moore

**OHIO POWER COMPANY'S RESPONSE
TO NATURAL RESOURCES DEFENSE COUNCIL'S
DISCOVERY REQUEST
PUCO CASE NO. 16-1852-EL-SSO
FIRST SET**

INTERROGATORY

NRDC-INT-1-014 On page 14, lines 10-11, of her Direct Testimony, Witness Moore states, "with the proposed increase in the customer charge more accurately reflecting the cost causation from customers' use of the distribution system." Please explain how the proposed increase more accurately reflects the cost causation from the customers' use of the distribution system. Specifically, please list the components of the distribution system for which the Company believes that cost causation is more accurately reflected by including the cost in a customer charge, rather than in an energy charge.

RESPONSE

The cost of providing distribution service do not vary with volumetric usage. Generally, the distribution system costs are affected by either peak demand imposed on the distribution facilities or by the number of customers served. If these costs are primarily recovered through an energy charge, the customer is sent a price signal that by lowering their usage they are lowering the cost imposed on the system even though they have not necessarily lowered the costs imposed on the system.

Prepared by: Selwyn J. Dias
Andrea E. Moore

OHIO POWER COMPANY'S RESPONSE TO NATURAL RESOURCES DEFENSE COUNCIL'S DISCOVERY REQUEST PUCO CASE NO. 16-1852-EL-SSO FIRST SET

INTERROGATORY

NRDC-INT-1-005 Please indicate the percentage of poles that would have been avoided if half the residential customers along an overhead primary feeder (e.g., every second customer) had never existed.

RESPONSE

The Company objects because it is unable to fully answer the hypothetical question posed in the absence of all of the pertinent assumptions and fact/circumstances that apply to the hypothetical scenario. Without waiving the foregoing objection(s) or any general objection the Company may have, the Company states as follows. The Company has not performed the requested analysis.

Prepared by: Counsel

Marginal Elasticity Sources

Authors	Date	Title	Link
Acton, Bridger, and Mowill	1976	Residential Demand for Electricity in Los Angeles-an Econometric Study of Disaggregated Data	http://www.rand.org/pubs/reports/R1899.html
McFadden, Puig, and Kirshner	1977	Determinants of Long-Run Demand for Electricity	http://eml.berkeley.edu/reprints/mcfadden/7_2.pdf
Barnes, Gillingham, and Hageman	1981	The Short-Run Residential Demand for Electricity	www.jstor.org/stable/1935850
Henson	1984	Electricity Demand Estimates under Increasing- Block Rates	www.arlis.org/docs/vol2/hydropower/APA_DOC_no._3448.pdf
Reiss and White	2001	Household Electricity Demand, Revisited	www.nber.org/papers/w8687.pdf
Xcel Energy Colorado	2012	Impact Analysis of Residential Two Tier, Inverted Block Rates	Attached
Orans et al,	2014	Are Residential Customers Price-Responsive to an Inclining Block Rate? Evidence from British Columbia	http://docslide.us/documents/are-residential-customers-price-responsive-to-an-inclining-block-rate-evidence.html

Xcel Energy®
RESPONSIBLE BY NATURE®

Impact Analysis of Residential Two Tier, Inverted Block Rates (IBR)

01/22/2013

PROCEDURAL HISTORY

- As a result of its generic investigation into customer incentives launched in 2008, the Commission directed the Company to file options for residential tiered (inverted block) rates in our next Phase II (rate design) filing.
- (For purposes of this presentation, I'm using the terms inverted block rates and tiered rates interchangeably.)
- In response to this directive, in May 2009 the Company filed for approval of a residential tiered rate structure that would:
  - be limited to the 4 summer months; and
  - have two summers tiers, with a rate of 5.1 cents per kWh applied to the first 500 kWh in a billing period, and a rate of 8 cents per kWh applied to all additional use.
- In 2010 the CPUC approved the Company's proposal with one modification: the first tier rate was set at 4.6 cents per kWh, and the second tier rate was set at 9 cents per kWh.
- These tiered rates were first implemented in the summer of 2010.

Purpose of Tiered Rates

- The primary purpose of the approved tiered rate structure was to encourage a more efficient use of energy during the summer, since summer peak loads drive the Company's generation and transmission capacity costs.
- These price signals could be provided without the higher metering costs associated with time-of-use rates and applied to all residential customers.
- The idea was that customers would respond to the higher price applied to their use above 500 kWh by reducing their energy use.
- The Company set its rates assuming that customers would reduce their summer energy use by 0.26% for each 1.0 % increase in the marginal price attributable to tiered rates.
- We also assumed that usage in all other months would decrease by 0.13% for each 1.0% decline in those rates.
- Elasticity estimates were based on an assumed customer response to their total kWh Rate.
- We always planned to "re-estimate" customer response based on actual data, particularly in the summer.

Xcel Energy®
RESPONSIBLE BY NATURE®

High-Level Approach to Estimating IBR Impact

- Accumulate multiple years of data to:
  - mitigate impacts of anomalies in data or customer response in any one year; and
  - test for any differences between short- and long-run impacts.
- Limit analysis to summer months.
- For each year analyzed, "back into" IBR impact by stripping away changes in residential use attributable to factors <u>other than</u> IBR rates.
- Compare estimated response based on actual data with assumed response at time IBR rates were approved – requires normalization of data to compare fairly the test year with the years for which we're measuring a response.

Caveats With Analysis

- Not easy to estimate or measure impact of a price signal – a lot of unknowns with regard to customer behavior:
  - Level of customer knowledge
  - Customer perceptions of their cost
  - Other influences on customer usage
  - Consistency in data from year to year

Steps Taken to Estimate IBR Impact

- Obtained actual raw usage data from Company records.

ADJUSTED DATA TO TEST YEAR CONDITIONS:

- Adjusted usage for billing administrative differences.
- Normalized usage for weather consistent with Test Year weather normalization approach.
- Adjusted usage for economic conditions that were different from the Test Year economic conditions.

CONCLUSION:

- IBR Impact is the resulting difference from the estimated 2010 Test Year Usage Per Customer <u>before IBR impacts taken into account.</u>

Xcel Energy®
RESPONSIBLE BY NATURE®

Adjustments to Residential Usage per Customer to Capture Differences from Test Year Conditions

- Billing Administrative Differences from Test Year: actual usage adjusted to reflect billing changes from Test Year:
  - May usage billed in June
  - Billing cycles per month
  - Average billing days per month
- Weather: Actual usage normalized assuming test-year weather
- Economic Conditions: Actual usage adjusted to net out usage impacts attributable to economic drivers:
  - Number of Customers
  - Base Economic Conditions
  - Demand Side Management (DSM) Impacts
  - Solar Rewards Impacts

Xcel Energy®
RESPONSIBLE BY NATURE®

Actual Unadjusted Residential Summer Monthly Usage Per Customer (kWh)

2010

- 714.6

2011

- 708.6

2012

- 761.6

Xcel Energy®
RESPONSIBLE BY NATURE®

Adjusted Summer Monthly Residential Usage Per Customer (kWh)

Test Year Forecast After IBR Impact

- 661.6

Actual Adjusted

2010

- 674.2

2011

- 656.8

2012

- 659.3

Xcel Energy®
RESPONSIBLE BY NATURE®

Resulting Estimate of IBR Impact on Summer Monthly Usage Per Customer (kWh)

2010 Test Year Estimate

- (25.1)

2010 Estimated Actual

- (12.5)

2011 Estimated Actual

- (29.9)

2012 Estimated Actual

- (27.4)

Comparison of IBR % Impact on Usage

2010 Prediction (Test Year)

- (3.65)%

2010 Actual

- (1.89)%

2011 Actual

- (4.36)%

2012 Actual

- (3.99)%

Xcel Energy®
RESPONSIBLE BY NATURE®

Approach for Estimating IBR Impact on System Peak

- Assumed a constant residential load factor.
- Assumed the impact of weather was uniform.
- Assumed annual system peak occurred in the summer months.
- Assumed a 75% coincidence between consumption change and change in peak demand.

Estimate of IBR Impact on System Peak

2010 Prediction
- (2.7)%

2010 Actual
- (1.4)%

2011 Actual
- (3.3)%

2012 Actual
- (2.9)%

Xcel Energy®
RESPONSIBLE BY NATURE®

SUMMARY OF IMPACTS

Month	Actual Unadjusted Usage Per Customer	Actual Adjusted or Estimated Energy Consumption Per Customer After IBR (kWh/month)	Adjusted Energy Consumption Per Customer Minus Test Year Unadjusted Consumption Per kWh (kWh/month)	Change in Energy Consumption (%)	% Change in Class Coincident Peak
2010 TEST YEAR					
Summer Months	686.7	661.6	(25.1)	-3.65%	-2.7%
ACTUAL 2010					
Summer Months	714.6	674.2	(12.5)	-1.89%	-1.4%
ACTUAL 2011					
Summer Months	708.6	656.8	(29.9)	-4.35%	-3.3%
ACTUAL 2012					
Summer Months	761.6	659.3	(27.4)	-3.99%	-2.9%

CONCLUSIONS FROM ANALYSIS

- Inverted Block Rates did lower residential summer usage by some amount.
- Average of customer responses during 2010, 2011 and 2012 similar to response predicted.
- Response in second and third years greater than response in first year.
- Despite level of uncertainty with estimated customer response, the results are based on analysis of entire population of residential customers – not a sample.

**OHIO POWER COMPANY'S RESPONSE
TO NATURAL RESOURCES DEFENSE COUNCIL'S
DISCOVERY REQUEST
PUCO CASE NO. 16-1852-EL-SSO
FIRST SET**

REQUEST FOR PRODUCTION OF DOCUMENTS

NRDC-RPD-1-027 Please provide any studies or documents available to the Company that estimate the extent to which a decrease in energy charges will increase energy usage by customers.

RESPONSE

The Company has not performed the requested analysis.

Prepared by: Andrea E. Moore

**OHIO POWER COMPANY'S RESPONSE
TO NATURAL RESOURCES DEFENSE COUNCIL'S
DISCOVERY REQUEST
PUCO CASE NO. 16-1852-EL-SSO
FIRST SET**

REQUEST FOR PRODUCTION OF DOCUMENTS

NRDC-RPD-1-012 Please provide the number of residential customers served by the Company, by county.

RESPONSE

See NRDC-RPD-1-012 Attachment 1 for the number of residential customers by county

Prepared by: Andrea E. Moore

Ohio Power Company
Columbus Southern Power Rate Zone
Residential Secondary Bundled Service
Breakdown of Charges Based on Entered Information

Billing Parameters

Metered kWh Usage: 1,000 kWh

Bill Calculation	Quantity			Rates: Generation	Rates: Transmission	Rates: Distribution	Rates: Total		Billing: Generation	Billing: Transmission	Billing: Distribution	Billing: Total
Customer Charge						$ 8.40	$ 8.40				$ 8.40	$ 8.40
Energy Charge	1,000 kWh		x			$ 0.0182747	$ 0.0182747	/kWh			$ 18.27	$ 18.27
Base Charges											**$ 26.67**	**$ 26.67**
Riders												
Universal Service Fund (first 833,000 kWh)	1,000 kWh		x			$ 0.0001430	$ 0.0001430	/kWh			$ 0.14	$ 0.14
Universal Service Fund (in excess of 833,000 kWh)	0 kWh		x			$ 0.0001430	$ 0.0001430	/kWh			$ -	$ -
kWh Tax (first 2000 kWh)	1,000 kWh		x			$ 0.00465	$ 0.00465	/kWh			$ 4.65	$ 4.65
kWh Tax (next 13,000 kWh)	0 kWh		x			$ 0.00419	$ 0.00419	/kWh			$ -	$ -
kWh Tax (in excess of 15,000 kWh)	0 kWh		x			$ 0.00363	$ 0.00363	/kWh			$ -	$ -
Residential Distribution Credit Rider	**$26.67**	Base (Dist)	x			-3.5807%	-3.5807%				$ (0.95)	$ (0.95)
Pilot Throughput Balancing Adjustment Rider	1,000 kWh		x			$ 0.0016693	$ 0.0016693	/kWh			$ 1.67	$ 1.67
Deferred Asset Phase-In Rider	**$26.67**	Base (Dist)	x			7.7300%	7.7300%				$ 2.06	$ 2.06
Generation Energy Rider	1,000 kWh		x	$ 0.0466600			$ 0.0466600	/kWh	$ 46.66			$ 46.66
Generation Capacity Rider	1,000 kWh		x	$ 0.0102700			$ 0.0102700	/kWh	$ 10.27			$ 10.27
Auction Cost Reconciliation Rider	1,000 kWh		x	$ (0.0010714)			$ (0.0010714)	/kWh	$ (1.07)			$ (1.07)
Power Purchase Agreement Rider	1,000 kWh		x				$ 0.0016624	/kWh				$ 1.66
Basic Transmission Cost Rider	1,000 kWh		x		$ 0.0142293		$ 0.0142293	/kWh		$ 14.23		$ 14.23
Energy Efficiency and Peak Demand Reduction Cost Recovery	1,000 kWh		x			$ 0.0031170	$ 0.0031170	/kWh			$ 3.12	$ 3.12
Economic Development Cost Recovery	**$26.67**	Base (Dist)	x			1.05864%	1.05864%				$ 0.28	$ 0.28
Enhanced Service Reliability	**$26.67**	Base (Dist)	x			7.34119%	7.34119%				$ 1.96	$ 1.96
gridSMART Phase 1 Rider		Month				$ 1.01	$ 1.01				$ 1.01	$ 1.01
Retail Stability Rider	1,000 kWh		x				$ 0.0015421	/kWh				$ 1.54
Distribution Investment Rider	**$26.67**	Base (Dist)	x			28.98750%	28.98750%				$ 7.73	$ 7.73
Alternative Energy Rider	1,000 kWh		x	$ 0.0010060			$ 0.0010060	/kWh	$ 1.01			$ 1.01
Riders Total									**$ 56.87**	**$ 14.23**	**$ 21.67**	**$ 95.97**
Base + Rider Total									**$ 56.87**	**$ 14.23**	**$ 48.34**	**$ 122.64**

	Current	Proposed
Total per-kWh charges	$ 109.74	$ 96.02
Total bill	$ 122.64	$ 122.94

Ohio Power Company
Ohio Power Rate Zone
Residential Secondary Bundled Service
Breakdown of Charges Based on Entered Information

Billing Parameters

Metered kWh Usage: 1,000 kWh

Bill Calculation	Quantity		Rates: Generation	Rates: Transmission	Rates: Distribution	Rates: Total		Billing: Generation	Billing: Transmission	Billing: Distribution	Billing: Total
Customer Charge					$ 8.40	$ 8.40				$ 8.40	$ 8.40
Energy Charge	1,000 kWh	x			$ 0.0182747	$ 0.0182747	/kWh			$ 18.27	$ 18.27
Base Charges										**$ 26.67**	**$ 26.67**
Riders											
Universal Service Fund (first 833,000 kWh)	1,000 kWh	x			$ 0.0010772	$ 0.0010772	/kWh			$ 1.08	$ 1.08
Universal Service Fund (in excess of 833,000 kWh)	0 kWh	x			$ 0.0001681	$ 0.0001681	/kWh			$ -	$ -
kWh Tax (first 2000 kWh)	1,000 kWh	x			$ 0.00465	$ 0.00465	/kWh			$ 4.65	$ 4.65
kWh Tax (next 13,000 kWh)	0 kWh	x			$ 0.00419	$ 0.00419	/kWh			$ -	$ -
kWh Tax (in excess of 15,000 kWh)	0 kWh	x			$ 0.00363	$ 0.00363	/kWh			$ -	$ -
Residential Distribution Credit Rider	**$26.67** Base (Dist)	x			-3.5807%	-3.5807%				$ (0.95)	$ (0.95)
Pilot Throughput Balancing Adjustment Rider	1,000 kWh	x			$ 0.0016641	$ 0.0016641	/kWh			$ 1.66	$ 1.66
Deferred Asset Phase-In Rider	**$26.67** Base (Dist)	x			7.7300%	7.7300%				$ 2.06	$ 2.06
Generation Energy Rider	1,000 kWh	x	$ 0.0466600			$ 0.0466600	/kWh	$ 46.66			$ 46.66
Generation Capacity Rider	1,000 kWh	x	$ 0.0102700			$ 0.0102700	/kWh	$ 10.27			$ 10.27
Auction Cost Reconciliation Rider	1,000 kWh	x	$ (0.0010714)			$ (0.0010714)	/kWh	$ (1.07)			$ (1.07)
Power Purchase Agreement Rider	1,000 kWh	x				$ 0.0016624	/kWh				$ 1.66
Basic Transmission Cost Rider	1,000 kWh	x		$ 0.0142293		$ 0.0142293	/kWh		$ 14.23		$ 14.23
Energy Efficiency and Peak Demand Reduction Cost Recovery	1,000 kWh	x			$ 0.0031170	$ 0.0031170	/kWh			$ 3.12	$ 3.12
Economic Development Cost Recovery	**$26.67** Base (Dist)	x			1.05864%	1.05864%				$ 0.28	$ 0.28
Enhanced Service Reliability	**$26.67** Base (Dist)	x			7.34119%	7.34119%				$ 1.96	$ 1.96
gridSMART Phase 1 Rider	Month				$ 1.01	$ 1.01				$ 1.01	$ 1.01
Retail Stability Rider	1,000 kWh	x				$ 0.0015421	/kWh				$ 1.54
Distribution Investment Rider	**$26.67** Base (Dist)	x			28.98750%	28.98750%				$ 7.73	$ 7.73
Alternative Energy Rider	1,000 kWh	x	$ 0.0010060			$ 0.0010060	/kWh	$ 1.01			$ 1.01
Phase-In Recovery Rider	1,000 kWh	x				$ 0.0055510	/kWh				$ 5.55
Riders Total								**$ 56.87**	**$ 14.23**	**$ 22.60**	**$ 102.45**
Base + Rider Total								**$ 56.87**	**$ 14.23**	**$ 49.27**	**$ 129.12**

	Current	Proposed
Total variable charges	$ 116.22	$ 102.50
Total bill	$ 129.12	$ 129.42

OHIO POWER COMPANY'S RESPONSE
TO NATURAL RESOURCES DEFENSE COUNCIL'S
DISCOVERY REQUEST
PUCO CASE NO. 16-1852-EL-SSO
FIRST SET

INTERROGATORY

NRDC-INT-1-013 Please explain whether the higher proposed customer charge ($18.40 by January 1, 2018, as described on pages 12 to 13 of Witness Moore's Direct Testimony) may encourage some customers who are eligible for the Percentage of Income Payment Plan and have consumption below the average residential usage to file for the Percentage of Income Payment Plan. If not, please explain why.

RESPONSE

As a premise for the question, the Company cannot verify that there are any PIPP eligible customers that are not already participating in the program. Further, the Company has not performed any studies that would indicate whether or not the higher proposed customer charge would encourage customers that are already eligible to participate in the PIPP plan (but chose not to participate to date) would begin participating if their usage was below the average usage.

Prepared by: Selwyn J. Dias
Andrea E. Moore

**OHIO POWER COMPANY'S RESPONSE
TO NATURAL RESOURCES DEFENSE COUNCIL'S
DISCOVERY REQUEST
PUCO CASE NO. 16-1852-EL-SSO
FIRST SET**

REQUEST FOR PRODUCTION OF DOCUMENTS

NRDC-RPD-1-028 Please provide any data on the bill frequency distribution of the Company's low-income residential customers, other than those on the Percentage of Income Payment Plan.

RESPONSE

The Company has not performed the requested analysis.

Prepared by: Andrea E. Moore

OHIO POWER COMPANY'S RESPONSE
TO NATURAL RESOURCES DEFENSE COUNCIL'S
DISCOVERY REQUEST
PUCO CASE NO. 16-1852-EL-SSO
FIRST SET

INTERROGATORY

NRDC-INT-1-010 On page 13, lines 7-10, of Witness Moore's Direct Testimony, Witness Moore states, "Distribution costs are incurred by sizing the distribution system to meet customer(s) peak kW demand usage. These costs vary by peak demand requirements, not by kWh usage or by simply connecting a customer to the system. These costs would ideally be collected through a demand charge..." Please answer the following questions regarding that statement:

A. Please explain what portion of the proposed residential customer charges would include collection of these demand-related costs.

B. Please explain whether Witness Moore's reference to "customer(s) peak kW demand usage" means one of the following:

i. each customer's maximum monthly demand, whenever it occurs;
ii. each customer's maximum annual demand, whenever it occurs;
iii. the customers' collective maximum demand on the particular piece of distribution equipment;
iv. or something else.

C. If Witness Moore's reference to "customer(s) peak kW demand usage" means each customer's maximum demand, regardless of timing, please explain how this measure of customer load determines the sizing of line transformers, feeders and substations.

i. Please provide a breakdown of the Company's annual demand-related distribution costs among the following components: secondary lines, line transformers, primary lines, and distribution substations.
ii. For each such component, please provide the Company's estimate of the ratio of total load on the average or typical component to the sum of the maximum demands of the customers served by that component.

D. To the extent Witness Moore believes that a residential customer's maximum demand, whenever it occurs, determines the cost of distribution equipment, please explain how that would be the case for:

i. The substation;
ii. The feeder; and
iii. The line transformer.

OHIO POWER COMPANY'S RESPONSE
TO NATURAL RESOURCES DEFENSE COUNCIL'S
DISCOVERY REQUEST
PUCO CASE NO. 16-1852-EL-SSO
FIRST SET

RESPONSE

A. In the combined rate design proposed by the Company in Case Nos. 11-351-EL-AIR and 11-352-EL-AIR, the Company identified its full cost residential customer charge as $8.40 per residential customer bill. Any increase above the $8.40 would recover the Company's demand-related costs.

B. The statement is a general statement representing that the cost of service study in Case Nos. 11-351-EL-AIR and 11-352-EL-AIR provides for the peak demands in allocation of the distribution system. Some equipment is based on the coincident peak of the system while others are a combination of the non-coincident peak as well as the annual non-coincident peak.

C. The secondary distribution system (secondary lines, secondary components of line transformers) are allocated using 50% of the customer's maximum demand and 50% of the annual customers demand. The primary system (primary lines, primary components of the line transformers) as well as substations are allocated based on the peak load.

i. See Schedule E3.2 in Case Nos. 11-351-EL-AIR and 11-352-EL-AIR.

ii. See Schedules WP E-3.2y and WP E 3.2x in Case Nos. 11-351-EL-AIR and 11-352-EL-AIR.

D. See response to C.

Prepared by: Andrea E. Moore

OHIO POWER COMPANY'S RESPONSE TO NATURAL RESOURCE DEFENSE COUNSIL'S DISCOVERY REQUEST PUCO CASE NO. 16-1852-EL-SSO et al. SECOND SET

INTERROGATORY

NRDC-INT-2-017 What is the difference between "non-coincident peak" and "annual non-coincident peak" as used in the Company's response to NRDC INT-1-010 (B)?

RESPONSE

Non-coincident peak was referring to the class maximum demand and annual non-coincident peak was referring to the sum of the individual customer maximum demand.

Prepared by: Andrea E. Moore

**OHIO POWER COMPANY'S RESPONSE TO
NATURAL RESOURCE DEFENSE COUNSIL'S
DISCOVERY REQUEST
PUCO CASE NO. 16-1852-EL-SSO et al.
SECOND SET**

INTERROGATORY

NRDC-INT-2-019 The Company's response to NRDC INT-1-010(C) states, "The primary system (primary lines, primary components of the line transformers) as well as substations are allocated based on the peak load." Please answer the following questions regarding that statement:
A. What "peak load" is being referred to in that response?
B. Is it contribution to the AEP Ohio coincident peak?
C. Or is it class non-coincident peak?

RESPONSE

A. The Company used a 6 coincident peak in the base distribution case.

B. Yes.

C. No.

Prepared by: Andrea E. Moore

E.5 Energy, Demand and Emissions Savings

Table 4 presents the projected incremental annual GWh energy savings for each year as well as cumulative annual through 2019, TRC test results, net present value benefits, lifetime energy saved in thousand MWh, and lifetime cost of saved energy in 2017 dollars per kWh over the three-year period from 2017 to 2019.

Table 4. Incremental Annual Energy (GWh) Savings at Meter – 2017 to 2019

Consumer Sector	2017	2018	2019	2019 Cumulative Annual	Percent of Plan Total	Total Resource Cost Test (TRC)	TRC NPV Benefits (million 2017$)	Lifetime Energy Saved (thousand MWh)	Lifetime Utility Cost of Saved Energy (2017$/ kWh)
Appliance Recycling	11.8	11.9	11.9	35.7	2.2%	1.3	$9.9	285	$0.033
Community Assistance	8.4	8.5	8.5	25.4	1.6%	0.8	($5.1)	385	$0.061
e3smart	6.8	6.8	6.9	20.5	1.3%	4.0	$10.5	262	$0.013
Efficient Products	64.5	61.1	57.0	182.6	11.3%	4.1	$96.8	2,615	$0.009
Behavior Change	75.0	75.0	75.0	75.0	4.6%	1.7	$2.9	225	$0.019
In-Home Energy	8.7	8.3	8.6	25.7	1.6%	1.5	$8.6	458	$0.032
New Home	4.7	4.8	6.1	15.6	1.0%	1.0	($0.5)	326	$0.022
Manufactured Home	2.2	2.5	2.5	7.2	0.4%	1.2	$0.7	145	$0.015
Intelligent Home & Demand Response	12.0	24.1	36.1	36.1	2.2%	1.2	$1.8	72	$0.148
Consumer Sector Total	**194.3**	**202.9**	**212.6**	**423.7**	**26.1%**	**2.0**	**$118.7**	**4,772**	**$0.023**
% Savings of Consumer Sector Sales	1.4%	1.4%	1.5%	3.0%	Note: Behavior Change and Intelligent Home & Demand Response savings are not cumulative.				

Business Sector	2017	2018	2019	2019 Cumulative Annual	Percent of Plan Total	Total Resource Cost Test (TRC)	TRC NPV Benefits (million 2017$)	Lifetime Energy Saved (thousand MWh)	Lifetime Utility CSE (2017$ / kWh)
Business Behavior Change	8.9	8.9	9.4	9.4	0.6%	1.3	$0.3	27	$0.031
Continuous Energy Improvement	19.8	23.2	23.1	66.0	4.1%	2.2	$9.3	330	$0.022
Data Center	16.6	17.1	14.3	48.0	3.0%	1.3	$3.5	240	$0.029
Efficient Products for Business	109.7	105.3	99.1	314.1	19.4%	1.9	$130.8	3,445	$0.011
New Construction and Major Renovation	27.6	28.2	28.8	84.6	5.2%	1.4	$17.0	994	$0.020
Express	14.4	14.8	14.7	43.9	2.7%	1.3	$9.8	397	$0.029
Microbusiness	9.9	9.7	10.1	29.7	1.8%	1.7	$9.2	330	$0.012
Process Efficiency	42.0	41.9	38.1	122.0	7.5%	2.4	$60.8	1,855	$0.008
Retro-Commissioning	8.6	9.4	10.2	28.2	1.7%	1.0	$0.2	141	$0.031
Self-Direct	13.2	13.3	13.4	39.9	2.5%	4.6	$18.7	390	$0.011
CHP	106.0	106.0	106.0	318.0	19.6%	1.2	$43.5	6,042	$0.0014
Business Sector Total	**376.8**	**377.9**	**366.9**	**1,103.7**	**68.0%**	**1.6**	**$297.4**	**14,191**	**$0.010**
% Savings of Sector Sales (includes Business & Cross Sectors)	1.3%	1.3%	1.3%	3.9%	Note: Behavior Change savings are not cumulative.				
Cross Sector	**2017**	**2018**	**2019**	**2019 Cumulative Annual**	**Percent of Plan Total**	**Total Resource Cost Test (TRC)**	**TRC NPV Benefits (million 2017$)**	**Lifetime Energy Saved (thousand MWh)**	**Lifetime Utility CSE (2017$ / kWh)**
Multifamily	5.8	6.0	6.2	18.0	1.1%	1.6	$5.4	274	$0.025
Agriculture	1.7	1.7	1.8	5.1	0.3%	2.0	$1.7	52	$0.015
T&D Loss Reductions	20.0	20.0	20.0	60.0	3.7%	NA	NA	NA	NA
Customer EE Assessment Survey	4.0	4.0	4.0	12.0	0.7%	1.7	NA	NA	NA
Cross Sector Total	**31.4**	**31.7**	**31.9**	**95.1**	**5.9%**	**0.5**	**($22.3)**	**326**	$0.11
Plan Total	**602.5**	**612.5**	**611.5**	**1,622.5**	**100%**	**1.6**	**$393.9**	**19,289**	**$0.014**
% Total Sales	1.33%	1.36%	1.35%	3.6%	Note: Business/Cross Sector and Plan Total NPV benefits include Other Costs.				

Note: The 2019 Cumulative Annual savings does not equal the sum of the 2017 to 2019 incremental annual values because of a variety of factors. Section totals may not sum to Plan totals due to rounding.

PLC-15 002

E.6 EE/PDRs Investment and Potential Job Creation

The estimated investment for these programs is approximately $97.5 million in each year from 2017-2019, for a total $292.5 million (inflation adjusted 2017$, not present value), as shown in Table 7.

Table 7. Estimated Annual Total Investments by Program (millions)

Consumer Sector	2017	2018	2019	2017-2019 Total (cumulative)	Percent of Plan Total
Appliance Recycling	$3.2	$3.4	$3.5	$10.1	3.5%
Community Assistance	$8.5	$8.5	$8.5	$25.5	8.7%
e3smart	$1.2	$1.2	$1.2	$3.7	1.3%
Efficient Products	$9.1	$8.7	$8.0	$25.8	8.8%
Behavior Change	$1.5	$1.5	$1.5	$4.5	1.5%
In-Home Energy	$5.3	$5.1	$5.2	$15.6	5.3%
New Home	$2.4	$2.4	$3.1	$7.9	2.7%
Manufactured Home	$0.7	$0.8	$0.8	$2.3	0.8%
Intelligent Home & DR (expense)	$3.0	$4.2	$5.5	$12.7	4.3%
Intelligent Home & DR (capital)	$2.3	$2.3	$2.3	$6.8	2.3%
Consumer Sector Total	**$37.2**	**$38.0**	**$39.6**	**$114.9**	**39.3%**
Business Sector	**2017**	**2018**	**2019**	**17-19 Total (cumulative)**	**Percent of Plan Total**
Business Behavior Change	$0.3	$0.3	$0.3	$0.9	0.3%
Continuous Energy Improvement	$2.3	$2.8	$2.7	$7.8	2.7%
Data Center	$2.6	$2.7	$2.2	$7.5	2.6%
Efficient Products for Business	$14.3	$13.7	$13.3	$41.3	14.1%
New Construction/Major Renovation	$6.8	$7.1	$7.2	$21.1	7.2%
Express	$4.1	$4.2	$4.2	$12.6	4.3%
Microbusiness	$1.4	$1.4	$1.4	$4.3	1.5%
Process Efficiency	$5.7	$5.6	$4.9	$16.2	5.5%
Retro-Commissioning	$1.5	$1.6	$1.7	$4.8	1.6%
Self-Direct	$1.5	$1.5	$1.5	$4.5	1.6%
CHP	$3.4	$3.4	$3.4	$10.2	3.5%
Energy Efficiency Auction	$0.2	$0.2	$0.2	$0.6	0.2%
T&D Customer Efficiency Projects	$0.2	$0.2	$0.2	$0.6	0.2%
Business Outreach	$1.6	$1.6	$1.7	$4.9	1.7%
Business Sector Total	**$46.1**	**$46.2**	**$45.2**	**$137.5**	**47.0%**

Cross Sector	2017	2018	2019	2017-2019 Total (cumulative)	Percent of Plan Total
Multifamily	$2.4	$2.5	$2.5	$7.4	2.5%
Agriculture	$0.3	$0.3	$0.3	$0.9	0.3%
Customer EE Assessment Survey	$0.2	$0.2	$0.2	$0.6	0.2%
Efficient Financing	$1.0	$1.0	$1.0	$3.0	1.0%
Community Energy Savers	$0.5	$0.5	$0.5	$1.5	0.5%
Education and Training	$0.4	$0.4	$0.4	$1.2	0.4%
Targeted Advertising	$6.0	$6.0	$6.0	$18.0	6.2%
Research and Development	$2.5	$2.5	$2.5	$7.5	2.6%
Cross Sector Total	**$13.3**	**$13.4**	**$13.4**	**$40.1**	**13.7%**
Plan Total Investment	**$96.6**	**$97.6**	**$98.2**	**$292.5**	**100.0%**

(1) Savings are not projected for Research and Development, T&D Customer Efficiency, Energy Efficiency Auction, gridSMART EE/PDR, and Community Energy Savers. AEP Ohio also will conduct program evaluation and other essential program support functions, such as compliance and reporting, database management, contracting and payables, and Plan cost-benefit analysis.
(2) Cross-Sector Costs include support and other services, including general education and training, and targeted advertising, efficient financing, and most of the activities listed in (1) above.
(3) Section or annual totals may not sum to Plan totals due to rounding.

To firm up cost estimates and make any necessary budget and schedule changes, AEP Ohio may re-negotiate existing contracts for ongoing programs or issue Requests for Proposals (RFPs) for implementation contractors to bid on the work, and require them to submit detailed budgets along with estimated savings and implementation schedules. All new programs may be competitively bid through an RFP process. The cost for incremental internal management and third party evaluation, measurement and verification activities, and future plan development is included in the cost of the Plan. It is anticipated that these costs will not exceed ten percent of the total costs for the Plan.

Potential Job Creation

To capture the full economic impacts of the investments in energy efficiency, three separate effects (direct, indirect, and induced) must be examined for each change in expenditure. The sum of these three effects yields the total effect resulting from a single expenditure.

- The **direct effect** refers to the on-site or immediate effects produced by expenditures. In the case of installing energy efficiency upgrades in a home or business, the direct effect is the on-site expenditures and jobs of the construction or trade contractors hired to carry out the work.
- The **indirect effect** refers to the increase in economic activity that occurs when a contractor or vendor receives payment for goods or services delivered and is

Total Resource Cost (TRC) Test: Measures are cost effective from this perspective if their avoided costs are greater than the sum of the measure costs and the EE/PDR program administrative costs.

AEP Ohio used the TRC test to guide which EE/PDR programs to include in the Plan, noting that the Plan as a whole passes the TRC test as required by the PUCO. Most measures passed the TRC test. The Plan and the EE/PDR programs in the Plan are cost effective by industry standards.
Table 9 presents the overall benefit cost ratios for the consumer sector, the business sector, and the cross sector, and the overall Plan including all costs from other activities.

Table 9. Cost-effectiveness Ratios – 2017 to 2019

Consumer Sector	Total Resource Cost Test (TRC)	Utility Cost Test (UCT)	Participant Cost Test (PCT)	Rate Impact Measure Test (RIM)
Appliance Recycling	1.3	1.3	N/A	0.3
Community Assistance	0.8	0.8	N/A	0.3
e3smart	4.0	4.0	22.8	0.4
Efficient Products	4.1	5.5	15.1	0.4
Behavior Change	1.7	1.7	N/A	0.2
In-Home Energy	1.5	1.8	5.9	0.5
New Home	1.0	1.7	2.9	0.4
Manufactured Home	1.2	2.0	4.2	0.3
Intelligent Home & Demand Response	1.2	1.1	2.3	0.6
Consumer Sector Total	**2.1**	**2.2**	**9.3**	**0.4**

Business Sector	Total Resource Cost Test (TRC)	Utility Cost Test (UCT)	Participant Cost Test (PCT)	Rate Impact Measure Test (RIM)
Business Behavior Change	1.3	1.7	6.5	0.4
Continuous Energy Improvement	2.2	2.4	30.4	0.3
Data Center	1.3	2.4	4.1	0.4
Efficient Products for Business	1.9	7.4	3.0	0.7
New Construction and Major Renovation	1.4	2.9	2.9	0.5
Express	1.3	3.2	2.9	0.6
Microbusiness	1.7	5.6	2.8	0.7
Process Efficiency	2.4	6.9	3.9	0.7
Retro-Commissioning	1.0	1.7	4.5	0.3
Self-Direct	4.6	7.0	11.7	0.5
CHP	1.2	28.7	0.9	1.3
Business Sector Total (includes Other Costs)	**1.6**	**6.4**	**2.4**	**0.7**
Cross Sector	**Total Resource Cost Test (TRC)**	**Utility Cost Test (UCT)**	**Participant Cost Test (PCT)**	**Rate Impact Measure Test (RIM)**
Multifamily	1.6	2.1	4.5	0.5
Agriculture	2.0	4.4	4.0	0.6
Customer EE Assessment Survey	1.7	1.7	1.7	0.3
Cross Sector Total (includes Other Costs)	**0.4**	**0.5**	**4.4**	**0.3**
Plan Total (includes Other Costs)	**(TRC)**	**(UCT)**	**(PCT)**	**(RIM)**
	1.6	**4.0**	**2.8**	**0.7**

Projected Net Benefits

The formulas used to determine the net benefits for each benefit-cost test are provided in Table 10. All tests are evaluated by calculating the net present values over the lifetimes of the measures covered by the 20-year planning horizon. The total net benefits for each benefit-cost test for the 2017-2019 EE/PDR Plan are calculated by subtracting the value(s) in the denominator of each formula from the value(s) in the numerator. For example, subtracting both Administrative Costs (B) and Incentive Costs (C) from the Avoided Costs (A) results in the the UCT net benefits. Table 11 presents the present value costs for the 2017-2019 EE/PDR Plan in present value 2017 dollars (8.29% discount rate). The Avoided Costs (A) and Bill Reductions (E) result from energy

C.3 Residential Measure Characteristics by Program

Table 43. Residential Measure Characteristics (at meter savings)

Efficiency Measure	Base Measure	Program	Decision Type	Units	Energy Impact (kWh/unit)	Coincident Summer Peak Impact (W/unit)	Measure Life	Base Incentive ($/unit)	Incremental Cost ($/unit)	Admin Cost ($/unit)
A/C Cycling	0 hours of control	Air Conditioning Control - Res	CTR	Per Home	481	2.08	1	$30.00	$100.00	$47.08
Refrigerator Retirement	Secondary Refrigerator	Appliance Recycling	REM	Refrigerator	727	0.15	8	$140.00	$0.00	$29.78
Freezer Retirement	Secondary Freezer	Appliance Recycling	REM	Freezer	640	0.16	8	$140.00	$0.00	$26.23
Air Source Heat Pump SEER 14.5, COP 2.49	Electric Resistance Forced Air Furnace	Community Assistance	RET	Ton	2,707	0.02	18	$1,006.25	$1,006.25	$1,524.92
ENERGY STAR® Window / Room AC (DUB)	EER 8.5 Window AC	Community Assistance	DUB	Unit	68	1.38	12	$29.90	$29.90	$38.29
Reduced ACHnat 0.3 - Heat Pump	ACH 0.6	Community Assistance	RET	Home	1,712	0.01	15	$530.00	$530.00	$964.61
Reduced ACHnat 0.3 - Central A/C - Non-EL Heat	ACH 0.6	Community Assistance	RET	Home	17	0.90	15	$530.00	$530.00	$9.59
Reduced ACHnat 0.3 - Central A/C - EL Heat	ACH 0.6	Community Assistance	RET	Home	3,407	0.00	15	$530.00	$530.00	$1,919.62
Ceiling Ins. R-30 - Heat Pump	R-25 Ceiling	Community Assistance	RET	1000 sqft footprint	98	0.02	20	$700.00	$700.00	$55.39
Ceiling Ins. R-30 - Central A/C - Non-EL Heat	R-25 Ceiling	Community Assistance	RET	1000 sqft footprint	2	0.90	20	$700.00	$700.00	$1.23
Ceiling Ins. R-30 - Central A/C - EL Heat	R-25 Ceiling	Community Assistance	RET	1000 sqft footprint	194	0.01	20	$700.00	$700.00	$109.55
Ceiling Insul R-45 - Heat Pump	R-25 Ceiling	Community Assistance	RET	1000 sqft footprint	262	0.02	20	$890.00	$890.00	$147.71
Ceiling Insul R-45 - Central A/C - Non-EL Heat	R-25 Ceiling	Community Assistance	RET	1000 sqft footprint	6	0.90	20	$890.00	$890.00	$3.28
Ceiling Insul R-45 - Central A/C - EL Heat	R-25 Ceiling	Community Assistance	RET	1000 sqft footprint	519	0.01	20	$890.00	$890.00	$292.14
Wall Insul. R-11 - Heat Pump	Un-Insulated Wall	Community Assistance	RET	1000 sqft wall area	2,028	0.05	25	$1,300.00	$1,300.00	$1,142.43
Wall Insul. R-11 - Central A/C - Non-EL Heat	Un-Insulated Wall	Community Assistance	RET	1000 sqft wall area	45	2.33	25	$1,300.00	$1,300.00	$25.37
Wall Insul. R-11 - Central A/C - EL Heat	Un-Insulated Wall	Community Assistance	RET	1000 sqft wall area	4,011	0.01	25	$1,300.00	$1,300.00	$2,259.49
Underbelly Insulation R-19 - Heat Pump	Un-Insulated Floor	Community Assistance	RET	100 sqft floor area	221	0.02	25	$122.00	$122.00	$124.63
Underbelly Insulation R-19 - Central A/C - EL Heat	Un-Insulated Floor	Community Assistance	RET	100 sqft floor area	438	0.01	25	$122.00	$122.00	$246.49
1W LED Night Light	7W Incandescent Light	Community Assistance	ROB	Lamp	20	0.00	8	$2.00	$2.00	$11.27
LED Lighting 8W - Indoor	60W Incandescent	Community Assistance	ROB	Lamp	38	0.08	15	$5.41	$5.41	$21.61

Efficiency Measure	Base Measure	Program	Decision Type	Units	Energy Impact (kWh/unit)	Coincident Summer Peak Impact (W/unit)	Measure Life	Base Incentive ($/unit)	Incremental Cost ($/unit)	Admin Cost ($/unit)
LED Lighting 8W - Outdoor	60W Incandescent	Community Assistance	ROB	Lamp	41	0.00	15	$5.41	$5.41	$23.03
LED Lighting 15W - Indoor	Mix of 75W and 100W incandescent	Community Assistance	ROB	Lamp	62	0.08	15	$8.59	$8.59	$35.16
LED Lighting 15W - Outdoor	Mix of 75W and 100W incandescent	Community Assistance	ROB	Lamp	67	0.00	15	$8.59	$8.59	$37.51
High Eff. Elec. Water Heat - Tank - .95 EF (DUB)	Average Existing Electric Water Heater - 0.90 EF	Community Assistance	DUB	Unit	176	0.09	20	$287.15	$287.15	$99.43
Heat Pump Water Heater - 2.0 EF	Standard Electric Water Heater - .945 EF	Community Assistance	ROB	Unit	1,685	0.09	10	$888.50	$888.50	$949.07
Heat Pump Water Heater - 2.0 EF (DUB)	Average Existing Electric Water Heater - 0.90 EF	Community Assistance	DUB	Unit	1,844	0.09	10	$492.39	$492.39	$1,039.03
Instantaneous Electric Water Heater - .99 EF	Standard Electric Water Heater - .945 EF	Community Assistance	ROB	Unit	145	0.09	13	$666.80	$666.80	$81.78
Instantaneous Electric Water Heater - .99 EF (DUB)	Average Existing Electric Water Heater - 0.90 EF	Community Assistance	DUB	Unit	305	0.09	13	$476.11	$476.11	$171.74
DHW Pipe Insulation R-4 10 feet	10 feet of uninsulated (R-1) Hot Water Pipe	Community Assistance	RET	10 Linear Feet	266	0.11	15	$55.00	$55.00	$149.86
Low Flow Faucet Aerator, 1.5 GPM - EDHW	Average Existing Stock Aerator (2.2 GPM)	Community Assistance	RET	Faucet	25	0.12	12	$2.80	$2.80	$13.80
Low Flow (1.25 GPM) showerhead	2.87 GPM Showerhead	Community Assistance	RET	Shower	237	0.11	9	$11.00	$11.00	$133.52
Efficient Refrigerator (ENERGY STAR® or Better) (DUB)	Average Existing Refrigerator	Community Assistance	DUB	Refrigerator	231	0.15	17	$832.88	$832.88	$129.92
Refrigerator Retirement	Secondary Refrigerator	Community Assistance	REM	Refrigerator	727	0.15	8	$140.00	$0.00	$409.50
ECM Fan Motor - Heat Pump	Std PSC HVAC Motor	Community Assistance	RET	Home	675	0.20	18	$90.68	$90.68	$380.27
ECM Fan Motor - Central A/C - Non-EL Heat	Std PSC HVAC Motor	Community Assistance	RET	Home	675	0.20	18	$90.68	$90.68	$380.27
ECM Fan Motor - Central A/C - EL Heat	Std PSC HVAC Motor	Community Assistance	RET	Home	675	0.20	18	$90.68	$90.68	$380.27
Shower Start/Stop	No Start/Stop on Shower	Community Assistance	RET	Unit	245	0.11	5	$24.95	$24.95	$138.11
Weatherstripping and Door Sweep	No Weatherstripping	e3smart	RET	Home	82	0.12	11	$1.00	$1.00	$8.35
1W LED Night Light	7W Incandescent Light	e3smart	RET	Lamp	20	0.00	8	$2.00	$2.00	$2.05
LED Lighting 8W - Indoor for Kit	60W Incandescent	e3smart	RET	Lamp	41	0.08	15	$5.41	$5.41	$4.20

Efficiency Measure	Base Measure	Program	Decision Type	Units	Energy Impact (kWh/unit)	Coincident Summer Peak Impact (W/unit)	Measure Life	Base Incentive ($/unit)	Incremental Cost ($/unit)	Admin Cost ($/unit)
LED Lighting 8W - Outdoor for Kit	60W Incandescent	e3smart	RET	Lamp	41	0.00	15	$5.41	$5.41	$4.19
LED Lighting 15W - Indoor for Kit	Mix of 75W and 100W incandescent	e3smart	RET	Lamp	62	0.08	15	$8.59	$8.59	$6.39
LED Lighting 15W - Outdoor for Kit	Mix of 75W and 100W incandescent	e3smart	RET	Lamp	67	0.00	15	$8.59	$8.59	$6.82
Low Flow (1.25 GPM) showerhead	2.87 GPM Showerhead	e3smart	RET	Shower	237	0.11	9	$2.75	$2.75	$24.28
Hot Water Temp Gauge (Tank Temperature Turn Down)	No Temp Gauge	e3smart	RET	Unit	151	0.09	4	$1.00	$1.00	$15.50
Low Flow Faucet Aerator, 1.5 GPM - EDHW -Kitchen	Average Existing Stock Aerator (2.2 GPM)	e3smart	RET	Faucet	25	0.12	12	$0.50	$0.50	$2.51
Low Flow Faucet Aerator, 1.5 GPM - EDHW - Bathroom	Average Existing Stock Aerator (2.2 GPM)	e3smart	RET	Faucet	42	0.12	12	$0.50	$0.50	$4.30
LED Lighting 8W - Indoor	60W Incandescent	Efficient Products	ROB	Lamp	38	0.08	15	$3.25	$5.41	$1.96
LED Lighting 8W - Outdoor	60W Incandescent	Efficient Products	ROB	Lamp	41	0.00	15	$3.25	$5.41	$2.09
LED Lighting 15W - Indoor	Mix of 75W and 100W incandescent	Efficient Products	ROB	Lamp	62	0.08	15	$5.00	$8.59	$3.20
LED Lighting 15W - Outdoor	Mix of 75W and 100W incandescent	Efficient Products	ROB	Lamp	67	0.00	15	$5.00	$8.59	$3.41
LED Lighting 8W - Indoor (CFL Base)	13W CFL	Efficient Products	ROB	Lamp	3	0.09	15	$3.25	$3.78	$0.16
LED Lighting 8W - Outdoor (CFL Base)	13W CFL	Efficient Products	ROB	Lamp	4	0.00	15	$3.25	$3.78	$0.22
LED Lighting 12W - Indoor (CFL Base)	23W CFL	Efficient Products	ROB	Lamp	6	0.09	15	$3.75	$3.78	$0.31
LED Lighting 12W - Outdoor (CFL Base)	23W CFL	Efficient Products	ROB	Lamp	9	0.00	15	$3.75	$3.78	$0.45
5W Chandelier LED bulb	20 -25W Incandescent Chandelier/Specialty Bulb	Efficient Products	ROB	Lamp	20	0.09	15	$3.75	$7.50	$1.01
Hardwired Dimmer Switch	Two 60W Bulbs without Dimmer Switch	Efficient Products	RET	Dimmer	24	0.21	10	$8.00	$30.00	$1.23
Indoor Wall-mounted Motion Sensor	Two 60W Bulbs without a Motion Sensor	Efficient Products	RET	Sensor	39	0.13	8	$20.00	$42.00	$2.01
Indoor Fixture-mounted Motion Sensor	Two 60W Bulbs without a Motion Sensor	Efficient Products	RET	Sensor	29	0.18	8	$20.00	$66.00	$1.47
Outdoor Motion Sensor	No Motion Sensor	Efficient Products	RET	Sensor	56	0.00	8	$20.00	$33.00	$2.86

Efficiency Measure	Base Measure	Program	Decision Type	Units	Energy Impact (kWh/unit)	Coincident Summer Peak Impact (W/unit)	Measure Life	Base Incentive ($/unit)	Incremental Cost ($/unit)	Admin Cost ($/unit)
Solar Water Heat (DUB)	Average Existing Electric Water Heater - 0.90 EF	Efficient Products	DUB	Unit	2,442	0.16	20	$2,250.00	$4,479.21	$125.05
DHW Pipe Insulation R-4 10 feet	10 feet of uninsulated (R-1) Hot Water Pipe	Efficient Products	RET	10 Linear Feet	266	0.11	15	$30.00	$55.00	$13.62
Low Flow Faucet Aerator, 1.5 GPM - EDHW	Average Existing Stock Aerator (2.2 GPM)	Efficient Products	RET	Faucet	25	0.12	12	$2.80	$2.80	$1.25
Low Flow (1.25 GPM) showerhead	2.87 GPM Showerhead	Efficient Products	RET	Shower	192	0.11	9	$6.00	$6.00	$9.83
VSD Pool Pump	Code Efficiency One Speed Pump	Efficient Products	ROB	Pump	1,170	1.46	10	$200.00	$750.00	$59.92
Premium Efficiency Pool Pumps	Code Efficiency One Speed Pump	Efficient Products	ROB	Pump	409	1.40	10	$25.00	$50.00	$20.95
Heavy Duty Outdoor Timer for Pool Pump	Pool Pump Run Continuously Without Timer	Efficient Products	RET	Pump	131	2.33	10	$25.00	$200.00	$6.69
Efficient Refrigerator (ENERGY STAR® or Better)	Code-Compliant Refrigerator	Efficient Products	ROB	Refrigerator	104	0.18	17	$50.00	$89.75	$5.30
Efficient Refrigerator (ENERGY STAR® or Better) (DUB)	Average Existing Refrigerator	Efficient Products	DUB	Refrigerator	231	0.15	17	$37.53	$37.53	$11.81
ENERGY STAR® Freezer	Code Freezer	Efficient Products	ROB	Freezer	36	0.16	11	$10.00	$35.00	$1.85
ENERGY STAR® Freezer (DUB)	Average Existing Freezer	Efficient Products	DUB	Freezer	256	0.16	11	$10.00	$72.17	$13.13
ENERGY STAR® Dehumidifier	Non-ENERGY STAR® Dehumidifier	Efficient Products	ROB	Dehumidifier	207	0.23	12	$25.00	$60.00	$10.58
5-plug Smart Strip Power Bar	No Sensor Power Strip	Efficient Products	RET	Power Strip	57	0.11	4	$10.00	$16.00	$2.89
7-plug Smart Strip Power Bar	No Sensor Power Strip	Efficient Products	RET	Power Strip	103	0.12	4	$10.00	$26.00	$5.26
ENERGY STAR® v. 5.3 Television	Code Compliant TV	Efficient Products	ROB	TV	272	0.15	6	$1.00	$1.00	$13.90
ENERGY STAR® Most Efficient Television	Code Compliant TV	Efficient Products	ROB	TV	314	0.15	6	$1.00	$1.00	$16.09
ENERGY STAR® Set Top Boxes	Non-ENERGY STAR® Set Top Boxes	Efficient Products	ROB	Box	62	0.07	5	$19.01	$19.01	$3.16
ENERGY STAR® Monitor	Code Compliant Monitor	Efficient Products	ROB	Monitor	14	0.13	5	$11.00	$11.00	$0.72
ENERGY STAR® Dishwasher - Elec DHW	Code Compliant Dishwasher (2013 Code)	Efficient Products	ROB	Dishwasher	37	0.10	11	$25.00	$50.00	$1.89
ENERGY STAR® Dishwasher - Elec DHW (DUB)	Average Existing Dishwasher (2010 Code)	Efficient Products	DUB	Dishwasher	85	0.10	11	$14.78	$14.78	$4.35

Efficiency Measure	Base Measure	Program	Decision Type	Units	Energy Impact (kWh/unit)	Coincident Summer Peak Impact (W/unit)	Measure Life	Base Incentive ($/unit)	Incremental Cost ($/unit)	Admin Cost ($/unit)
ENERGY STAR® Dishwasher - Non-EL DHW	Code Compliant Dishwasher (2013 Code)	Efficient Products	ROB	Dishwasher	16	0.10	11	$25.00	$50.00	$0.83
ENERGY STAR® Dishwasher - Non-EL DHW (DUB)	Average Existing Dishwasher (2010 Code)	Efficient Products	DUB	Dishwasher	64	0.10	11	$14.78	$14.78	$3.29
Convection Oven	Conventional Oven	Efficient Products	ROB	Oven	67	0.54	12	$50.00	$50.00	$3.45
Clothes Washer - Tier 3 >= 2.2 MEF-w/gas or no dry	Fed Standard 1.72 MEF	Efficient Products	ROB	Unit	130	0.14	11	$50.00	$101.43	$6.64
Clothes Washer - Tier 3 >= 2.2 MEF-w/gas or no dry (DUB)	Average Existing Clothes Washer (1.04 MEF)	Efficient Products	DUB	Unit	173	0.14	11	$29.98	$29.98	$8.86
Clothes Washer - Tier 3 >= 2.2 MEF-w/elec dry	Fed Standard 1.72 MEF	Efficient Products	ROB	Unit	393	0.14	11	$50.00	$101.43	$20.12
Clothes Washer - Tier 3 >= 2.2 MEF-w/elec dry (DUB)	Average Existing Clothes Washer (1.04 MEF)	Efficient Products	DUB	Unit	524	0.11	11	$29.98	$29.98	$26.84
Heat Pump Clothes Dryer (CEF >= 5.0) (Elec Dry)	Standard Vented Electric Dryer (CEF = 3.73)	Efficient Products	ROB	Unit	137	0.18	14	$350.00	$350.00	$7.00
ENERGY STAR® Air Purifier/Cleaner	Non-ENERGY STAR® Air Purifier/Cleaner	Efficient Products	ROB	Purifier	569	0.11	9	$50.00	$70.00	$29.15
High Performance Circulating Pump (DHW)	Conventional Circulator Pump on HW tank	Efficient Products	ROB	Pump	354	0.09	15	$50.00	$300.00	$18.13
Home Energy Report	No Report	HER	BEH	Home	200	0.05	1	$0.00	$0.00	$4.00
Tier 1 GSHP, Closed Loop, water to air	SEER 14, 11 EER Air Source Heat Pump	In-Home Energy	ROB	Ton	518	0.07	18	$500.00	$1,203.00	$199.12
Tier 1 GSHP, Closed Loop, water to air (DUB)	SEER 10, Air Source Heat Pump	In-Home Energy	DUB	Ton	829	0.19	18	$500.00	$525.00	$318.25
Tier 2 GSHP, Closed Loop, water to air	SEER 14, 11 EER Air Source Heat Pump	In-Home Energy	ROB	Ton	653	0.10	18	$500.00	$1,203.00	$250.85
Tier 2 GSHP, Closed Loop, water to air (DUB)	SEER 10, Air Source Heat Pump	In-Home Energy	DUB	Ton	963	0.19	18	$500.00	$525.00	$369.98
Tier 3 GSHP, Closed Loop, water to air	SEER 14, 11 EER Air Source Heat Pump	In-Home Energy	ROB	Ton	712	0.11	18	$500.00	$1,203.00	$273.55
Tier 3 GSHP, Closed Loop, water to air (DUB)	SEER 10, Air Source Heat Pump	In-Home Energy	DUB	Ton	1,022	0.19	18	$500.00	$525.00	$392.68

Efficiency Measure	Base Measure	Program	Decision Type	Units	Energy Impact (kWh/unit)	Coincident Summer Peak Impact (W/unit)	Measure Life	Base Incentive ($/unit)	Incremental Cost ($/unit)	Admin Cost ($/unit)
Tier 1 GSHP, Open Loop, water to air	SEER 14, 11 EER Air Source Heat Pump	In-Home Energy	ROB	Ton	691	0.10	18	$500.00	$1,203.00	$265.45
Tier 1 GSHP, Open Loop, water to air (DUB)	SEER 10, Air Source Heat Pump	In-Home Energy	DUB	Ton	1,001	0.19	18	$500.00	$525.00	$384.57
Tier 2 GSHP, Open Loop, water to air	SEER 14, 11 EER Air Source Heat Pump	In-Home Energy	ROB	Ton	801	0.12	18	$500.00	$1,203.00	$307.49
Tier 2 GSHP, Open Loop, water to air (DUB)	SEER 10, Air Source Heat Pump	In-Home Energy	DUB	Ton	1,111	0.19	18	$500.00	$525.00	$426.62
Tier 3 GSHP, Open Loop, water to air	SEER 14, 11 EER Air Source Heat Pump	In-Home Energy	ROB	Ton	936	0.14	18	$500.00	$1,203.00	$359.42
Tier 3 GSHP, Open Loop, water to air (DUB)	SEER 10, Air Source Heat Pump	In-Home Energy	DUB	Ton	1,246	0.20	18	$500.00	$525.00	$478.54
Air Source Heat Pump SEER 15, COP 2.49	SEER 14, 11 EER Air Source Heat Pump	In-Home Energy	ROB	Ton	95	0.48	18	$200.00	$274.15	$36.35
Air Source Heat Pump SEER 15, COP 2.49 (DUB)	SEER 10, Air Source Heat Pump	In-Home Energy	DUB	Ton	662	0.25	18	$119.64	$119.64	$254.44
SEER 15 CAC - Non-EL Heat	SEER 13.0 CAC	In-Home Energy	ROB	Ton	68	0.90	18	$50.00	$184.25	$26.10
SEER 15 CAC - Non-EL Heat (DUB)	SEER 10.0 CAC	In-Home Energy	DUB	Ton	221	0.90	18	$50.00	$80.41	$84.81
SEER 15 CAC - EL Heat	SEER 13.0 CAC	In-Home Energy	ROB	Ton	68	0.90	18	$100.00	$184.25	$26.10
SEER 15 CAC - EL Heat (DUB)	SEER 10.0 CAC	In-Home Energy	DUB	Ton	221	0.90	18	$80.41	$80.41	$84.81
Ductless Mini Split HP SEER 15	Ductless Mini Split HP SEER 13	In-Home Energy	ROB	Ton	76	1.29	15	$25.00	$50.00	$29.23
Ductless Mini Split HP SEER 18	Ductless Mini Split HP SEER 13	In-Home Energy	ROB	Ton	159	1.29	15	$200.00	$377.11	$60.90
ENERGY STAR® Window / Room AC	CEER 10.9 Window AC	In-Home Energy	ROB	Unit	17	1.27	12	$16.19	$16.19	$6.40
ENERGY STAR® Window / Room AC (DUB)	EER 8.5 Window AC	In-Home Energy	DUB	Unit	68	1.27	12	$25.00	$29.90	$26.10
Ground Source Heat Pump (Elec Res Base)	Electric Baseboard Heating	In-Home Energy	RET	Ton	3,118	0.01	18	$2,000.00	$6,031.03	$1,197.66
ENERGY STAR® Air Source Heat Pump (Elec Res Base)	Electric Baseboard Heating	In-Home Energy	RET	Ton	2,612	0.02	18	$500.00	$1,809.31	$1,003.37
ECM Fan Motor - Heat Pump	Std PSC HVAC Motor	In-Home Energy	RET	Home	675	0.20	18	$50.00	$90.68	$259.28
ECM Fan Motor - Central A/C - Non-EL Heat	Std PSC HVAC Motor	In-Home Energy	RET	Home	675	0.20	18	$50.00	$90.68	$259.28
ECM Fan Motor - Central A/C - EL Heat	Std PSC HVAC Motor	In-Home Energy	RET	Home	675	0.20	18	$50.00	$90.68	$259.28
Duct Sealing and Insulation - Heat Pump	Leaky Un-Insulated Ducts	In-Home Energy	RET	Home	1,511	0.02	20	$70.00	$760.00	$580.48
Duct Sealing and Insulation - CAC - Non-EL Heat	Leaky Un-Insulated Ducts	In-Home Energy	RET	Home	35	0.98	20	$70.00	$760.00	$13.46
Duct Sealing and Insulation - CAC - EL Heat	Leaky Un-Insulated Ducts	In-Home Energy	RET	Home	3,430	0.01	20	$70.00	$760.00	$1,317.60

Efficiency Measure	Base Measure	Program	Decision Type	Units	Energy Impact (kWh/unit)	Coincident Summer Peak Impact (W/unit)	Measure Life	Base Incentive ($/unit)	Incremental Cost ($/unit)	Admin Cost ($/unit)
CAC Tune-Up	No Tune-Up	In-Home Energy	RET	Ton	30	0.40	5	$25.00	$192.50	$11.57
NEST Consumer Controls - Heat Pump - (DUB)	Non-Programmable Thermostat	In-Home Energy	DUB	Home	804	0.00	15	$70.00	$98.61	$308.79
NEST Consumer Controls - Non-EL Heat - (DUB)	Non-Programmable Thermostat	In-Home Energy	DUB	Home	50	0.00	15	$35.00	$98.61	$19.39
Reduced ACHnat 0.3 - Heat Pump	ACH 0.6	In-Home Energy	RET	Home	1,712	0.01	15	$200.00	$530.00	$657.69
Reduced ACHnat 0.3 - Central A/C - Non-EL Heat	ACH 0.6	In-Home Energy	RET	Home	17	0.90	15	$50.00	$530.00	$6.54
Reduced ACHnat 0.3 - Central A/C - EL Heat	ACH 0.6	In-Home Energy	RET	Home	3,407	0.00	15	$200.00	$530.00	$1,308.83
ENERGY STAR® 50 CFM Bathroom Ventilating Fan	Code-Compliant Ventilating Fan	In-Home Energy	ROB	Fan	88	0.11	19	$20.00	$43.50	$33.80
Solar Attic Ventilation Fans	Passive Ventilation	In-Home Energy	RET	Fan	8	0.98	10	$10.00	$500.00	$3.15
Ceiling Ins. R-30 - Heat Pump	R-25 Ceiling	In-Home Energy	RET	1000 sqft footprint	98	0.02	20	$225.00	$700.00	$37.77
Ceiling Ins. R-30 - Central A/C - Non-EL Heat	R-25 Ceiling	In-Home Energy	RET	1000 sqft footprint	2	0.90	20	$225.00	$700.00	$0.84
Ceiling Ins. R-30 - Central A/C - EL Heat	R-25 Ceiling	In-Home Energy	RET	1000 sqft footprint	194	0.01	20	$225.00	$700.00	$74.69
Ceiling Insul R-45 - Heat Pump	R-25 Ceiling	In-Home Energy	RET	1000 sqft footprint	262	0.02	20	$225.00	$890.00	$100.71
Ceiling Insul R-45 - Central A/C - Non-EL Heat	R-25 Ceiling	In-Home Energy	RET	1000 sqft footprint	6	0.90	20	$90.00	$890.00	$2.24
Ceiling Insul R-45 - Central A/C - EL Heat	R-25 Ceiling	In-Home Energy	RET	1000 sqft footprint	519	0.01	20	$225.00	$890.00	$199.18
Wall Insul. R-11 - Heat Pump	Un-Insulated Wall	In-Home Energy	RET	1000 sqft wall area	2,028	0.05	25	$225.00	$1,300.00	$778.93
Wall Insul. R-11 - Central A/C - Non-EL Heat	Un-Insulated Wall	In-Home Energy	RET	1000 sqft wall area	45	2.33	25	$225.00	$1,300.00	$17.30
Wall Insul. R-11 - Central A/C - EL Heat	Un-Insulated Wall	In-Home Energy	RET	1000 sqft wall area	4,011	0.01	25	$225.00	$1,300.00	$1,540.56
ENERGY STAR® Double Pane Windows - Heat Pump (DUB)	Single Pane Windows	In-Home Energy	DUB	100 sqft window area	847	0.17	25	$82.36	$82.36	$325.35
ENERGY STAR® Double Pane Windows - Central A/C - Non-EL Heat (DUB)	Single Pane Windows	In-Home Energy	DUB	100 sqft window area	294	0.50	25	$82.36	$82.36	$112.93
ENERGY STAR® Double Pane Windows - Central A/C - EL Heat (DUB)	Single Pane Windows	In-Home Energy	DUB	100 sqft window area	999	0.15	25	$82.36	$82.36	$383.60
Triple Pane Windows - Heat Pump (DUB)	Single Pane Windows	In-Home Energy	DUB	100 sqft window area	1,439	0.15	25	$137.27	$137.27	$552.92
Triple Pane Windows - Central A/C - Non-EL Heat	Single Pane Windows	In-Home Energy	DUB	100 sqft window area	464	0.48	25	$90.00	$137.27	$178.11

PLC-16 007

Efficiency Measure	Base Measure	Program	Decision Type	Units	Energy Impact (kWh/unit)	Coincident Summer Peak Impact (W/unit)	Measure Life	Base Incentive ($/unit)	Incremental Cost ($/unit)	Admin Cost ($/unit)
(DUB)										
Triple Pane Windows - Central A/C - EL Heat (DUB)	Single Pane Windows	In-Home Energy	DUB	100 sqft window area	2,415	0.09	25	$137.27	$137.27	$927.74
Window Film (west facing windows)	No Film	In-Home Energy	RET	100 sqft window area	178	0.53	10	$200.00	$267.00	$68.52
ENERGY STAR® Door - Heat Pump	Average Existing Door (1.75 " thick wood, R-3.2)	In-Home Energy	RET	Door	30	0.02	20	$15.00	$64.71	$11.61
ENERGY STAR® Door - Non-EL Heat	Average Existing Door (1.75 " thick wood, R-3.2)	In-Home Energy	RET	Door	1	0.98	20	$15.00	$64.71	$0.26
ENERGY STAR® Door - EL Heat	Average Existing Door (1.75 " thick wood, R-3.2)	In-Home Energy	RET	Door	60	0.01	20	$15.00	$64.71	$22.97
1W LED Night Light	7W Incandescent Light	In-Home Energy	RET	Lamp	20	0.00	8	$1.00	$2.00	$7.68
LED Holiday Lights (300 bulb string)	300 x 0.48 W Incandescent Lights	In-Home Energy	RET	300 bulb string	26	0.00	15	$5.00	$10.00	$10.09
High Eff. Elec. Water Heat - Tank - .95 EF (DUB)	Average Existing Electric Water Heater - 0.90 EF	In-Home Energy	DUB	Unit	176	0.09	20	$50.00	$287.15	$67.79
Heat Pump Water Heater - 2.0 EF	Standard Electric Water Heater - .945 EF	In-Home Energy	ROB	Unit	1,685	0.09	10	$500.00	$888.50	$647.09
Heat Pump Water Heater - 2.0 EF (DUB)	Average Existing Electric Water Heater - 0.90 EF	In-Home Energy	DUB	Unit	1,844	0.09	10	$242.39	$242.39	$708.43
Instantaneous Electric Water Heater - .99 EF	Standard Electric Water Heater - .945 EF	In-Home Energy	ROB	Unit	145	0.09	13	$400.00	$666.80	$55.76
Instantaneous Electric Water Heater - .99 EF (DUB)	Average Existing Electric Water Heater - 0.90 EF	In-Home Energy	DUB	Unit	305	0.09	13	$226.11	$226.11	$117.10
Drain Water Heat Recovery (42% efficient or higher)	No Heat Recovery	In-Home Energy	RET	Unit	391	0.00	25	$250.00	$760.00	$150.05
Shower Start/Stop	No Start/Stop on Shower	In-Home Energy	RET	Unit	245	0.11	5	$10.00	$24.95	$94.17
Waterbed Insulating Pad	No Pad	In-Home Energy	RET	Pad	490	0.01	6	$17.50	$35.00	$188.22
Residential Solar PV	Average Ohio Home w/o Solar PV	In-Home Energy	RET	kW Output	1,202	0.58	25	$1,000.00	$10,000.00	$461.59

Efficiency Measure	Base Measure	Program	Decision Type	Units	Energy Impact (kWh/unit)	Coincident Summer Peak Impact (W/unit)	Measure Life	Base Incentive ($/unit)	Incremental Cost ($/unit)	Admin Cost ($/unit)
ENERGY STAR® Manufactured Homes - EL Heat	Average Manufactured Home	Manufactured Home	NEW	Home	11,947	0.04	20	$2,500.00	$5,000.00	$1,223.74
Reduced ACHnat 0.3 - Heat Pump	ACH 0.6	New Home	NEW	Home	1,712	0.01	15	$200.00	$530.00	$526.15
Reduced ACHnat 0.3 - Central A/C - Non-EL Heat	ACH 0.6	New Home	NEW	Home	17	0.90	15	$50.00	$530.00	$5.23
Reduced ACHnat 0.3 - Central A/C - EL Heat	ACH 0.6	New Home	NEW	Home	3,407	0.00	15	$200.00	$530.00	$1,047.07
ENERGY STAR® 50 CFM Bathroom Ventilating Fan	Code-Compliant Ventilating Fan	New Home	NEW	Fan	88	0.11	19	$20.00	$43.50	$27.04
ENERGY STAR® Double Pane Windows - Heat Pump	Double Pane Windows	New Home	NEW	100 sqft window area	363	0.17	25	$50.00	$150.00	$111.55
ENERGY STAR® Double Pane Windows - Central A/C - Non-EL Heat	Double Pane Windows	New Home	NEW	100 sqft window area	126	0.50	25	$50.00	$150.00	$38.72
ENERGY STAR® Double Pane Windows - Central A/C - EL Heat	Double Pane Windows	New Home	NEW	100 sqft window area	428	0.15	25	$50.00	$150.00	$131.52
Triple Pane Windows - Heat Pump	Double Pane Windows	New Home	NEW	100 sqft window area	617	0.15	25	$180.00	$250.00	$189.57
Triple Pane Windows - Central A/C - Non-EL Heat	Double Pane Windows	New Home	NEW	100 sqft window area	199	0.48	25	$75.00	$250.00	$61.07
Triple Pane Windows - Central A/C - EL Heat	Double Pane Windows	New Home	NEW	100 sqft window area	1,035	0.09	25	$90.00	$250.00	$318.08
Heat Pump Water Heater - 2.0 EF	Standard Electric Water Heater - .945 EF	New Home	NEW	Unit	1,685	0.09	10	$125.00	$888.50	$517.67
Drain Water Heat Recovery (42% efficient or higher)	No Heat Recovery	New Home	NEW	Unit	391	0.00	25	$250.00	$660.00	$120.04
ENERGY STAR® 3.0 Qualified Home - Heat Pump	Code Construction	New Home	NEW	Home	3,389	0.15	20	$1,000.00	$2,329.00	$1,041.26
ENERGY STAR® 3.0 Qualified Home - Central A/C - Non-EL Heat	Code Construction	New Home	NEW	Home	1,259	0.39	20	$1,000.00	$2,329.00	$387.03
ENERGY STAR® 2.0/2.5 Qualified Home - Heat Pump	Code Construction	New Home	NEW	Home	3,393	0.16	20	$500.00	$1,674.00	$1,042.62
ENERGY STAR® 2.0/2.5 Qualified Home - Central A/C - Non-EL Heat	Code Construction	New Home	NEW	Home	1,135	0.47	20	$500.00	$1,674.00	$348.80

PLC-16 009