STATE OF MARYLAND

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of the Energy Efficiency, Conservation and Demand Response Programs Pursuant to the Empower Maryland Energy Efficiency Act of 2008	)	**Case No. 9153, et al.**

DIRECT TESTIMONY OF

PAUL CHERNICK

ON BEHALF OF

THE OFFICE OF PEOPLE'S COUNSEL

Resource Insight, Inc.

JANUARY 30, 2015

TABLE OF CONTENTS

TABLE OF EXHIBITS

I. Identification & Qualifications

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

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

Q: Summarize your professional education and experience.

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

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

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

Q: Have you testified previously in utility proceedings?

A: Yes. I have testified nearly three hundred times on utility issues before various regulatory, legislative, and judicial bodies, including utility regulators in thirty states and five Canadian provinces, and two US Federal agencies. This testimony has included the many reviews of utility cost-allocation studies, revenue-allocation proposals and rate designs.

Q: Have you testified previously before the Commission?

A: Yes. I have testified approximately 16 times before the Commission, from 1990 through 2014, as follows:

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

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

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

II. Introduction

Q: On whose behalf are you testifying?

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

Q: What is the scope of your testimony?

A: My testimony covers aspects of the avoided costs developed by the Maryland Energy Administration (MEA) and used by some of the utilities in screening their EmPOWER Maryland utilities, particularly with respect to the estimation of the demand-reduction-induced price effects (DRIPE) for electric capacity. I discuss aspects of the mathematical and practical bases of DRIPE, as well as available empirical data useful in estimating DRIPE.

In addition, I discuss the equity issues raised by recognition of DRIPE statewide and appropriate testing of the equity of utility portfolios.

Q: Which utilities participate in EmPOWER Maryland?

A: The participating utilities are as follows:

- Baltimore Gas & Electric (BGE),
- Potomac Electric Power Company (PEPCo),
- Delmarva Power & Light (DP&L),
- Potomac Edison,
- Southern Maryland Electric Cooperative (SMECo),
- Washington Gas Light (WGL).

Other than WGL, all of these utilities are electric utilities with electric energy-efficiency programs that may also have incidental gas savings, while WGL and BGE are natural-gas utilities with gas energy-efficiency programs that may also have incidental electric savings. Some energy-efficiency measures for one energy source may increase usage of the other energy source (such as reduced electric waste heat increasing gas heating requirements), and some energy-efficiency measures replace usage of one fuel with the other (e.g., replacing electric space heating with a gas furnace). Hence, avoided costs for both electricity and gas are relevant for all six utilities.

Q: How is the rest of your testimony structured?

A: The rest of this introduction describes demand-reduction-induced price effects (DRIPE) and the PJM locational pricing system that drives Maryland DRIPE, and the following sections address the DRIPE values assumed by the MEA and the utilities, improvements in the filed energy DRIPE values, historical and prospective capacity market conditions in PJM, and my recommendations for corrected capacity DRIPE values.

Q: Why is it important to make reasonable estimates of the avoided costs, and particularly the DRIPE values?

A: The values of the avoided costs may determine the cost-effectiveness of a wide range of utility activities, including consumer energy efficiency, distributed generation, demand response, dynamic pricing, smart-grid applications, and utility efficiency programs (conservation voltage reduction, low-loss transformers). Higher avoided costs support higher levels of all these activities, so identifying the appropriate efforts requires reasonable avoided-cost estimates.

Just as important, different categories of avoided costs support different types of activities. For example, higher avoided energy costs justify greater energy-efficiency efforts, while higher avoided capacity costs and capacity DRIPE will tend to justify more demand-response efforts. In particular, the strikingly high capacity DRIPE assumed by the utilities (as illustrated in MEA's EmPOWER 2015–2017 Cost Effectiveness Framework at 12) greatly increases the estimated benefit of near-term demand response. Inappropriate estimates of avoided costs will tend to misdirect utility efforts to less-productive activities

In addition to the effects of avoided costs on planning, both BGE and PEPCo use avoided costs, including capacity DRIPE, to compute their incentives for operating their residential load-management programs.[1] Inappropriate estimates of avoided costs will tend to misdirect incentive funds.

[1]Avoided costs and net benefits of demand-side management programs have been widely used in setting utility incentives throughout North America over the last 25 years or so.

Q: How much do your estimates of avoided costs vary from those developed by the MEA and used by the utilities?

A: The only avoided costs for which I have quantified estimates that differ significantly from MEA's estimates are those for capacity DRIPE. My analysis results in levelized values about 70% less than MEA's for the MAAC utilities.

A. Demand-Reduction-Induced Price Effects

Q: What is DRIPE?

A: Reducing demand for any normal commodity in a competitive market will tend to reduce the price at which the market clears. Over the last decade or so, this price suppression has come to be called the Demand-Reduction-Induced Price Effect or DRIPE.

Q: Should DRIPE be considered a benefit of energy-efficiency and demand-response programs?

A: Yes. Reductions in market prices reduce costs for all customers who purchase generation services from the market, either through utility standard-offer service or through competitive electric suppliers.

Q: Which utility prices are subject to DRIPE?

A: Reductions in electric load reduce both electric energy prices and electric capacity prices. Reductions in gas load (through both improved end-use gas efficiency and reduced fuel use at marginal gas-fired electric plants) reduce both the cost of gas in the continental supply markets (such as at Henry Hub) and the basis for delivery to the city gate. The lower supply costs reduce prices for both end-use consumers of gas (through the LDCs) and generators, thus reducing market electric prices to the extent that gas is the marginal fuel. The lower basis also reduces electric prices, but has little effect on the costs of LDCs, which typically purchase the vast majority of their gas transportation under long-term, cost-of-service contracts.

Q: How can DRIPE be measured?

A: The effect of load reductions on prices is not observed directly, in contrast to the way that avoided capacity costs can be observed from the results of the PJM forward auctions (up to three years out), or avoided energy costs the historical day-ahead and real-time energy markets. Electric energy DRIPE can be estimated from historical relationship between hourly loads and market prices, or from production-costing models (although the latter can be problematic). Capacity DRIPE can be estimated from examination of recent (and possibly forecast) demand and supply curves for the RPM market.

Q: Is DRIPE an avoided cost, comparable to avoided energy or capacity?

A: Yes, in most respects. One significant difference is that the direct avoided costs benefit the customers of the utility running the programs, while DRIPE benefits counted in screening energy-efficiency for any utility includes savings to customers of all the state's utilities.[2] In most situations, this should not be a problem, since each utility's programs benefit the customers of the others and every utility's customers should be better off with the additional energy-efficiency spending that may result from including DRIPE in screening. Nonetheless, it is conceivable that one utility will spend a disproportionately large amount of money on programs that generate lots of DRIPE benefits while its peers do not reciprocate. If the Commission suspects that program spending is becoming unbalanced among the utilities, it should require each utility to review the benefits its customers receive (the sum of direct avoided costs, the

[2]A few New England jurisdictions include DRIPE benefits outside the state.

customers' share of DRIPE benefits from that utility's programs, and their share of DRIPE benefits from the programs of the other utilities) and determine whether the customer benefits on a utility basis exceed that utility's spending.

B. PJM Locational Pricing

Q: How do PJM pricing rules affect avoided costs in Maryland?

A: PJM operates the day-ahead and real-time energy markets, setting a price for energy delivered to the distribution company systems in each of 20 zones, corresponding to utility (for PEPCo, DPL and BGE) or holding-company (for Potomac Edison) transmission territory.[3] PJM also operates a forward capacity market (the Reliability Pricing Mechanisms, or RPM) in which it takes bids roughly three years before the beginning of a June to May delivery year, in a Base Residual Auction (BRA), supplemented by incremental auctions in each of the next two years. The BRA sets the price for the vast majority of capacity. The latest BRA occurred in May 2014 for 2017/18 delivery.

Q: For what regions does PJM determine market prices in the BRAs?

A: Each BRA sets prices (which may be the same) for the entire PJM RTO, 20 internal zones (named for the transmission owner in the zone, generally the dominant utility), and a few sub-zones to reflect current and recent constraints within a zone (e.g., PSEG North, DPL South). For most cases, PJM determines prior to the auction that a zone will not be transmission-constrained from its neighboring zones. Then, for analysis purposes, PJM bundles each set of zones without mutual constraints into a Locational Deliverability Area (LDA). Those LDAs may be nested; for example, the BGE and PEPCo zones are part of the

[3] The PEPCo zone includes SMECo.

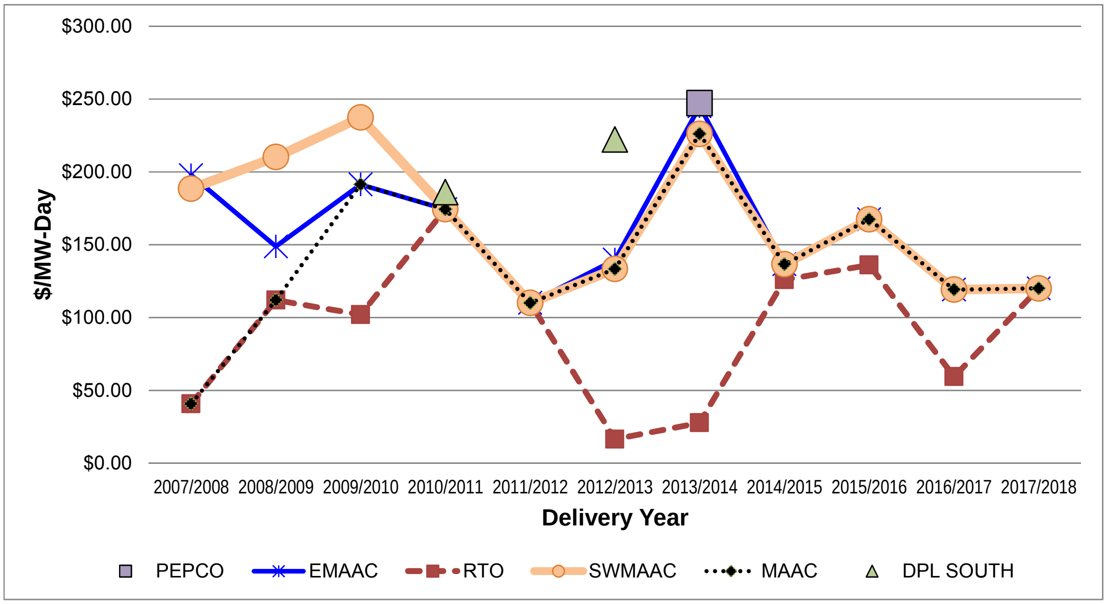
SWMAAC LDA, which is part of the MAAC LDA (along with EMAAC, which includes the DPL zone), which is in turn part of the RTO LDA. Potomac Edison is part of the APS zone, which is part of the RTO LDA, without any intermediate LDA.

Of the four utility areas in Maryland, only the APS zone has consistently been in the same LDA—the unconstrained RTO—over all 11 BRAs. In the BRAs for 2007/08 through 2009/10, the SWMAAC and EMAAC prices separated from the RTO price. For 2010/11 and 2011/12, prices for all the LDAs serving Maryland merged with the RTO. For the next five BRAs, all of MAAC separated from the RTO. Other than a spike in the DPL South zone in 2012/13, the Maryland MAAC LDAs have all cleared at very similar prices in the last eight BRAs.

In the latest BRA, for 2017/18, MAAC pricing merged again with the RTO, due to such factors as PJM's reduction of capacity imports and the failure to clear the auction of four Exelon nuclear units in Illinois (Quad Cities and Byron).[4] The following chart illustrates the clearing prices for the Maryland LDAs and the previously described price mergers and separation for the eleven BRAs.

[4] Exelon's Oyster Creek in EMAAC also failed to clear.

Figure 1: Historical RPM BRA Clearing Prices for Maryland LDAs



Source: PJM RTM results

III. The Filed Estimates of Price Effects

Q: What was the source of the utility estimates of DRIPE?

A: Three utilities—BGE, PEPCo, and DPL—included capacity DRIPE in their screening of energy-efficiency programs. All these utilities rely on estimates of energy DRIPE by Exeter Associates for MEA, and capacity DRIPE presented in the MEA's filing of August 18, 2014.[5]

Q: Which avoided cost components will you discuss in this section?

A: My analysis focuses on energy DRIPE, avoided capacity cost, and capacity DRIPE.

[5] "Avoided Energy Costs in Maryland: Assessment of the Costs Avoided through Energy Efficiency and Conservation Measures in Maryland; Final Report." Prepared by Exeter Associates for the Power Plant Research Program of the Maryland Department of Natural Resources, April 2014. MEA's filing includes the Exeter Report, Avoided Cost Summary Tables for 2015–2017, a memo entitled EmPOWER 2015-2017 Cost Effectiveness Framework, and a table entitled VRR Curve Capacity DRIPE. It is entry ML 157744 of the Commission's maillog system.

A. *Filed Energy DRIPE*

Q: How did Exeter estimate Energy DRIPE?

A: Exeter calculated the hourly marginal prices for 2015–2030 for each of three zones (APS, SWMAAC and EMAAC) that cover parts of Maryland, for the following four load cases:

1. a base case,
2. a case with SWMAAC load reduced by 200 MW in each hour,
3. a case with APS load reduced by 150 MW in each hour, and
4. a case with EMAAC load reduced by 300 MW in each hour.

Exeter interpreted the price differential between Cases 2 and 1, divided by 200, as the price effect of one megawatt load reduction in SWMAAC; the differential between Cases 3 and 1, divided by 150, as the price effect of one megawatt load reduction in APS, and the differential between Cases 4 and 1, divided by 300, as the price effect of one megawatt load reduction in EMAAC. Exeter then averaged the on-peak prices in each load-price combination for each year, as well as averaging the off-peak prices. Exeter computed these effects for prices in all three zones, for a load change in each of the three zones, for a total of 18 load-price coefficients in each year (2 periods times three load-reduction zones, times three price-reduction zones).

Exeter decayed the estimated DRIPE effects by 20% annually starting with the installation date. Exeter says (at 36), "The decay scaling factor for a measure installed in 2015, therefore, would be equal to 0.33 by year 5 (2019) and equal to 0.11 by year 10 (2024)."[6] That explanation implies that the effect decays 20% in the year of installation (if the decay started in 2016, the scaling factor in 2019 would be 41%).

[6] Exeter, Avoided Energy Costs in Maryland, April 2014.

Exeter adopted those decayed results for measures installed in 2015 and 2016. For measures installed in 2017, Exeter shifted the 2016 values forward (later) by one year and reduced them by 15%. Exeter (at 34) justified the lower 2017 values because "that is the first year in which the Ventyx model builds new power plants in the…Base Case."

To derive an estimate of the benefit in each zone, Exeter took the price effect (in $/MWh per MW of load reduction) for each zone, multiplied that effect by annual Maryland energy consumption in the zone, and divided by the number of annual hours in the relevant (on- or off-peak) period.

Q: Was Exeter's development of the energy DRIPE appropriate?

A: While the approach was not an unreasonable initial effort, the following aspects should be improved.

First, the results of production costing models, such as the Ventyx model that Exeter used, vary from run to run, depending on how random events (such as plant outages) are timed and how maintenance outages are scheduled. Even listing resources in a different order can result in a different cost estimate, by determining which unit is out of service at a particular time. In addition, if the generic sizes of new generation units in the model do not match well the size of the energy-efficiency savings, the model may defer resources that would produce much more or much less energy than the load decrement. It is not clear how much of the price differences that Exeter found were modeling artifacts, as opposed to actual differences in marginal costs as a function of load. For example, Exeter reports that a reduction in APS load in 2015 increases prices in SWMAAC, which is unlikely. Lower load in APS frees up energy from a generator that will either be turned down (if it is the most expensive generation running) replace some more-expensive generator serving SWMAAC (reducing the market price in SWMAAC), or replace some more expensive generator serving another LDA. Depending on which of these cases applies, the APS load reduction can have either (1) no effect on SWMAAC, (2) a strong benefit, or (3) something in between. In the future, the analysts should take care to isolate the load-related effects from the model artifacts, and explain those efforts. Alternatively, MEA might try using statistical modeling of historical loads and prices, as has been the norm for estimating energy-DRIPE in New England.

Second, Exeter assumed the energy-efficiency load decrement would be the same in every hour of the peak or off-peak period, through all the months of the year. That load shape may be representative for some energy-efficiency measures (e.g., efficient exit-sign lights), but many measures will be concentrated in high-value months (summer for air conditioning, winter for space heating). Even within each month, the benefits will tend to be higher in high-load hours (on hot summer days, cold winter days). In the future, MEA should develop energy DRIPE values for typical measure load shape (e.g., one proportional to load) or different values for different measure types.

Third, Exeter assumed that the price reductions flow to consumers immediately. In reality, when load reductions decrease market prices a significant share of customer load will still be under contracts struck before the reductions occurred. Unless the market participants have accurately forecast the energy DRIPE effect and embedded that effect in earlier contracts, the price benefits will not be entirely realized for months or years after installation.

Fourth, Exeter has not explained its decay assumption. This assumption might reflect some mix of responses to lower market prices, including retail price elasticity (rebound), accelerated retirements, delayed resource additions, and deferred improvements in heat rates and reliability. It also appears that the

Ventyx modeling includes changes in resource additions, so that portion of the price response may be double counted, in the modeling and in the decay.

Finally, Exeter does not adequately justify its treatments of installations in 2017, specifically the 15% reduction from the lagged 2016 energy DRIPE.

Q: How should the shortcomings in Exeter's computation of energy DRIPE be addressed?

A: The issues I describe above should be addressed by MEA as soon as possible, and certainly before any additional important decisions are made relying on these values. Evaluating or correcting the problems in Exeter's results will require access to Exeter's analysis details and to data that I do not currently possess, so I cannot propose alternative values at this time.

B. Filed Capacity DRIPE

1. In the Current EmPower Maryland Cases

Q: How did MEA develop the capacity DRIPE used in the utility filings?

A: As discussed in the MEA's EmPOWER 2015-2017 Cost Effectiveness Framework and demonstrated in the VRR Curve Capacity DRIPE table, MEA estimated the slope of the Variable Resource Requirement (VRR) curve (the administrative equivalent of a demand curve) from PJM filings of Planning Period Parameters documents, and the supply curve from graphics that PJM has provided for three BRAs.[7] The analysis assumed that the MAAC and rest-of-RTO zones would stay separate for capacity pricing and have no effect on one

[7]2014/2015 Base Residual Auction Report Addendum, 2015/2016 Base Residual Auction Supply Curves, and 2016/2017 Base Residual Auction Supply Curves, all available at www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/.

another, so MEA estimated two DRIPE effects: one for Potomac Edison and the other for all the Maryland utilities in MAAC.

Q: How did MEA derive the capacity DRIPE from the supply and demand curves?

A: While I cannot trace MEA's computations through from the VRR Curve Capacity DRIPE document to the DRIPE results tabulated in Avoided Cost Summary Tables for 2015–2017 (at 3, 5, and 7), it appears that MEA performed the following steps:

1. determined the slope of the VRR curve in the range of moderate surplus (the "B-C Slope" in the terminology of the VRR Curve Capacity DRIPE document) for the MAAC LDA and for the Rest-of-RTO LDA for each delivery year 2014/15 through 2017/18;
2. assumed that the load and supply conditions in MAAC do not affect prices in the rest of the RTO, and that conditions in the Rest-of-RTO LDA do not affect prices in MAAC;
3. divided the slope of each VRR curve by two;
4. multiplied the result by the capacity requirement for the Maryland portion of each LDA;
5. reduced the effect by two thirds in the year of installation and one third in the second year, to reflect the lag in recognition of load reductions in PJM's capacity auctions
6. Reduced the effect by 20% in each of the first five years, for a reduction of 67% by year five, and linearly to zero in year ten, reflecting offsetting market responses.

Q: What problems have you identified in this computation?

A: I have identified the following four problems:

- assuming that the prices in MAAC and the rest of the RTO will always be separate, resulting in higher capacity prices (and DRIPE) for the three eastern utilities and lower prices and DRIPE for Potomac Edison;
- assuming that, when the prices separate, supply in MAAC does not affect price in rest-of-RTO, and vice versa;
- assuming that the effect of energy-efficiency supply on price equals half the slope of the VRR, and is independent of the slope of the supply curve;
- understating the lag in recognition of load reductions in PJM's estimation of capacity requirements and hence capacity prices.

Q: What is wrong with assuming that the prices in MAAC and the rest of the RTO will always be separate?

A: The two regions cleared at the same price for 2017/18. As I discuss in Section V, there are good reasons to expect the prices will be the same in many future years.

Q: What is wrong with assuming that supply in MAAC does not affect price in rest-of-RTO, and vice versa?

A: There are two problems. First, MAAC is part of the RTO, so increased supply (or reduced load) in MAAC almost inevitably reduces the RTO capacity price, as well as the price in MAAC. Second, PJM's sensitivity analyses of the results of the BRAs indicate that increasing supply in the RTO generally reduces prices in MAAC, as I discuss in Section VI.A, below.

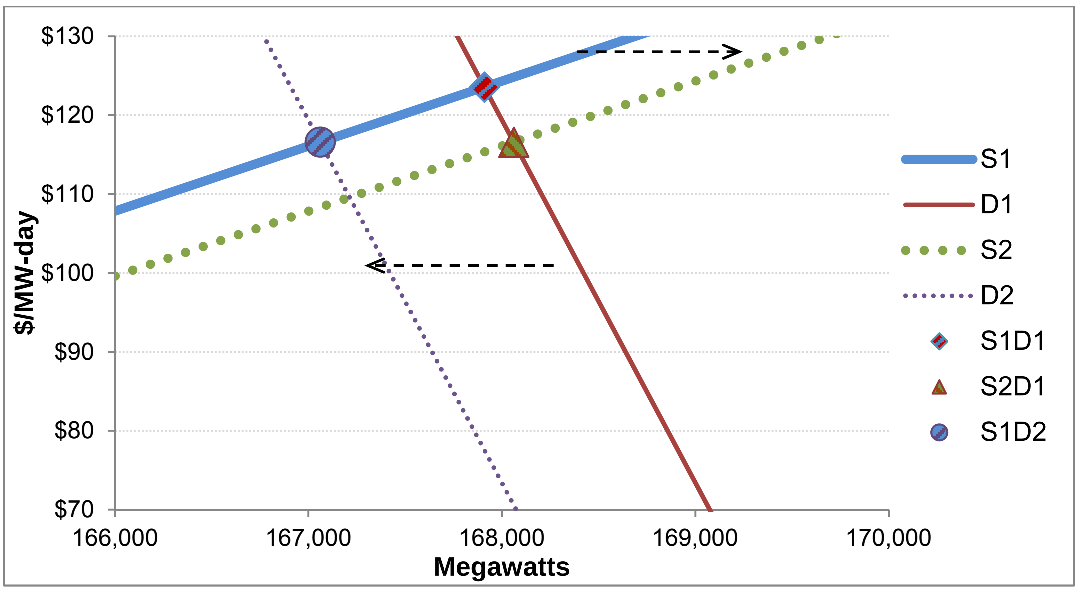
Q: What is MEA's rationale for assuming that the price effect of additional energy efficiency equals half the slope of the VRR?

A: I cannot find any explanation for this position in the record. It is my impression that this outcome was the result of negotiation among the utilities and MEA.

Q: How should MEA have computed the price effect of energy reductions?

A: The effect of additional energy efficiency on the market-clearing capacity depends on both the slope of the VRR and the slope of the supply curve. Figure 2 illustrates the effect of adding 1,000 MW of peak reduction as an increase of supply (shifting the S_1 supply curve to the S_2 supply curve) or a decrease in demand (shifting the D_1 VRR curve to the D_2 VRR curve). The dashed lines show a 1,000 MW shift in the supply curve to the right, or the demand curve to the left.

Figure 2: Illustration of PJM Capacity Clearing Prices and Shifts



In addition to the actual clearing price (point S_1D_1), Figure 2 shows the effect of shifting the supply curve 1,000 MW to the right (point S_2D_1, reflecting addition of 1,000 MW of EE&C bid into the auction) and the effect of shifting the demand curve 1,000 MW to the left (point S_1D_2, reflecting 1,000 MW reduction in the demand curve from reflecting the same amount of EE&C in the forecast driving the demand curve). In each case, the 1,000 MW of EE&C reduces the market-clearing price by about $7/MW-day.

Exhibit PLC-2 shows that this equivalence is not a coincidence. Assuming that effects on losses and reserves are treated equivalently, the effect of a load reduction on price is the same, regardless of whether PJM includes the reduction as an incremental resource or a decrement in load.

Q: Did MEA estimate this effect of shifting the supply or demand curve?

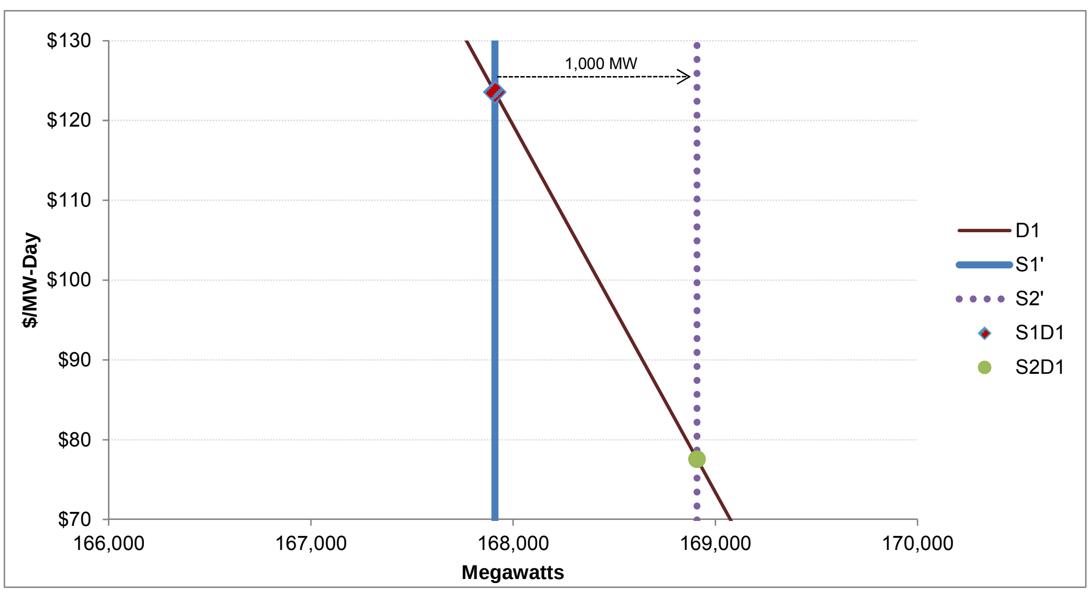
A: Yes. The VRR Capacity DRIPE document computes "DRIPE from 1 MW shift of VRR Curve," which is the change in market price from a one-MW shift, equivalent to the shift point S_1D_1 to point S_2D_1 in Figure 2. The same document refers to that price change times the affected MW in Maryland as the benefit of shifting to the "New Equilibrium."

Unfortunately, MEA and the utilities ignored this result and instead assumed a much higher value for each BRA.

Q: What price shift did MEA and the utilities assume?

A: The assumed price shift is half the effect that would occur if the supply curve were vertical. The situation with a vertical supply curve is shown in Figure 3.

Figure 3: Illustration of PJM Capacity Clearing Prices with Shift Down VRR Curve



This is exactly the price change that BGE uses in its demand-response-incentive computation, as I describe in Section III.B.2 the utilities and MEA recognized that the assumption of a vertical supply curve was implausible, since MEA had already estimated supply curves that were distinctly not vertical. Obviously, some resources would clear at higher prices but drop out at lower prices.

The PJM BRA supply curves for capacity are not really smooth, but composed of a series of steps, representing the individual bids. The utilities and MEA effectively assumed that the slope of the supply curve was such that there was a 50% chance that a small shift in energy-efficiency supply would result in the VRR moving through a vertical portion of the supply curve, having the effect shown in Figure 3, and a 50% chance that the VRR would pass through a horizontal portion of the supply curve, having no effect.

Q: Do you have any documentation of this 50% assumption?

A: In its demand-response incentive methodology (discussed in Section III.B.2), PEPCo explains that it used the

> Maryland Energy Administration EmPOWER 2014 adopted process, assuming a 45 degree slope of the demand curve, which results in a 50 percent application of the resulting change of the Variable Resource Requirements supply curve of Points B to C.

Q: Does this explanation make sense?

A: No. PEPCo's explanation describes the VRR curve as the supply curve, when in fact the VRR curve is PJM's administrative alternative to a market demand curve. It is meaningless to describe how the 45° demand curve intersects the VRR demand curve. I assume that PEPCo misunderstood the comments of other parties on an EmPOWER Planning Group call, and garbled a proposal to assume a 45° supply curve and the VRR demand curve.

In addition, any claim about what a 45° supply curve would do is completely meaningless, since the slope of the supply curve depends on the units and scale on which the curve is drawn. The supply curve plots dollars-per-MW-day against megawatts supplied; the units on the two axes are entirely different and cannot be put on the same scale. The x-axis megawatt scale could use 1,000 MW per inch, or 10,000 MW; the y-axis price scale could use $10/MW-day per inch, or $50. A supply curve that was a 45% angle at one combination of these scales would have an entirely different slope with a different combination.

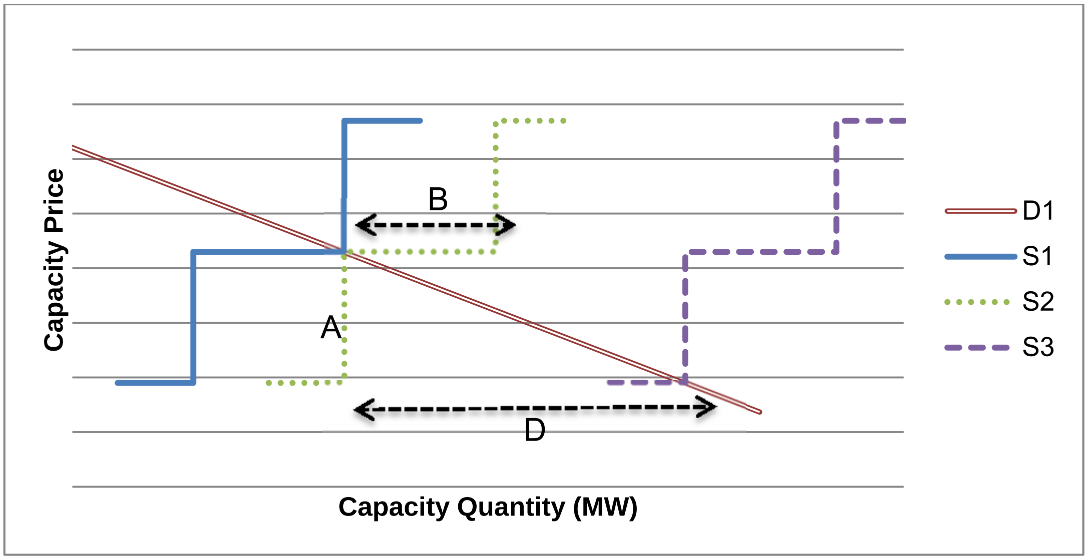
The fact that our only written justification of the 50% VRR computation relies on such profound confusion suggest just how arbitrary it is.

Q: Is the 50% assumption consistent with the available data?

A: No. The 50% assumption would only be correct for a very specific relationship between the slopes of the VRR curve and the supply curve. With the actual slopes of those curves, shifting the supply curve would change the price much less than half the time.

Figure 4 illustrates how the price would change given a fixed demand curve and changing quantities of supply.

Figure 4: Illustration of PJM Capacity Clearing Prices, Stepped Supply Curve



Shifting the supply curve to the right, along the horizontal section of the supply curve, by *B* MW, from the original supply curve S_1 to supply curve S_2, results in no change in price, but reduces the capacity supplied by the marginal resource. A further shift of the supply curve, by *D* MW, from S2 to S3, moves the intersection down a vertical section of the curve, substantial decreasing the clearing price and increasing the quantity taken.

The ratio of the energy-efficiency resources that cause no price change (*B* MW) and that reduce the price (*D* MW) represents the probability that any particular change in energy-efficiency resources would intersect a horizontal or a vertical leg. In the example in Figure 4, shifting the supply curve would change the price about 67% of the time. More generally, the value of *B* for the average step of the VRR can be quantified as $^A/_{m_S}$, where m_S is the average slope of the supply curve and *D* as $-(^A/_{m_{VRR}})$, where m_{VRR} is the slope of the VRR curve. The ratio of the energy-efficiency additions causing a price change to those causing no price change is thus:

$$\frac{D}{B} = \frac{m_s}{-m_{VRR}}$$

In other words, the ratio of the probability of a price change to the probability of no price change is equal to the slope of the supply curve divided by the negative of the slope of the demand curve (slope times −1). With this formula, it is possible to calculate the odds ratio of changed prices to unchanged prices given PJM's actual VRR curve and the estimated supply curve slope for each year. Table 1 depicts these ratios in PJM over a four year period. All of these ratios are lower (and most much lower) than the 1.0 odds ratio implied by the MEA-utility 50% VRR solution.

Table 1: Odds Ratio of Price Change to No Price Change

LDA	2014–15	2015–16	2016–17	2017–18
RTO	0.34	0.39	0.18	0.17
MAAC	0.78	0.45	0.23	0.20

Table 2 restates the odds ratio as a probability of a price change, comparable to the 50% probability assumed by MEA and the utilities.

Table 2: Probability of a Price Change from an Energy-Efficiency Increment

LDA	2014–15	2015–16	2016–17	2017–18
RTO	25%	28%	15%	14%
MAAC	44%	31%	19%	17%

An increase in resources reduces price much less than half the time. The 50% VRR assumption still overstates DRIPE by as much as three times.

Q: How does your analysis of Figure 4 differ from the assumptions of MEA and the utilities in adopting the VRR?

A: I do not know. Neither the MEA nor the utilities have provided any analysis supporting the 50% VRR approach. The adoption of this assumptions appears to have been entirely arbitrary.

Q: Why do you say that MEA understated the lag in recognition of load reductions in PJM's capacity market?

A: The utilities appear to bid about half of their projected energy-efficiency savings into the BRA for the forecast first year of savings, three years in the future. This conservatism makes sense, since the utilities will generally not have regulatory approval for their energy-efficiency plans three years in the future (the bids for 2017/18, for example, were due in May 2014, several months before the Commission's approval of the 2015–2017 energy-efficiency plans). Also, the effectiveness of the programs for any particular year is unknown and the extent to which PJM will accept claimed savings is also unknown. Indeed, the PJM protocols for monitoring and verification for peak savings may be less generous than the Commission-approved savings estimation methodologies.[8]

Q: What happens to the load reductions that are not bid into the BRA for the first year in which the energy-efficiency savings reduce the summer peak?

A: The utilities may bid some of the additional capacity into the incremental auctions for that first year, but those resources are not likely to have any significant effect on the prices paid by consumers. They may also bid the capacity into the BRAs for later years, but the data provided by BGE (and confidential data from PEPCo and DPL) do not indicate clearly that the utilities actually do so.

[8] In addition to these reasonable bases for conservatism, BGE can increase the revenues of Exelon Generation by reducing the capacity that it bids into the market. The ratepayers get less credit for the energy-efficiency capacity, and pay higher prices for their capacity needs, while Exelon increases its profits. If the Exelon-PHI merger is confirmed, the same incentive to low-ball capacity bid into the BRAs will also apply to PEPCo and DPL.

Q: What would be the effect of load reductions that the utilities never bid into the BRAs?

A: Any load reductions that are not bid into the auctions will affect prices only after they are incorporated into PJM's econometric load forecast. Of the 2015 energy-efficiency installations, only about half will affect the 2015 summer peak, which will be used in the 2016 forecast that will determine the amount of capacity acquired in 2016 for the 2019/20 delivery year. The peak reduction from all the 2015 installations will affect the peaks in 2017 and later years.

It will take a few years for the auction results to reflect the load reductions fully, since only the last years of the data will be reduced. Depending on the details of the variability of load over time, the 2016 load forecast for the summer of 2019 might reflect only about 25% of the 2015 load reduction; that fraction might rise to about 50% by the 2017 forecast for the 2020 peak and over 90% by time of the 2019 forecast of the 2021 peak.

Q: What is the effect of the delay in recognizing the non-bid load reductions?

A: While MEA and the utilities assume that all the market price effects of the load reductions occurs in the year the measure is installed, the benefits of load reductions that are not bid into the BRAs (and thus only reflected in the PJM load forecast) will be delayed by five or six years.

Q: How does hedging of retail prices affect capacity DRIPE?

A: As I discuss with respect to energy in Section III.B.2, not all capacity purchased for retail load will be affected by reductions in market prices in the short term, due to existing purchase contracts for the utility SOS and fixed-price multi-year contracts between customers and competitive electric suppliers.

2. In the Load-Control Rider Filings

Q: Which utilities recover an incentive based on capacity DRIPE for operating their residential load-control programs?

A: Both BGE and PEPCo have such shareholder incentives.

Q: How does PEPCo use capacity DRIPE in its incentive computation?

A: On December 12, 2014, PEPCo filed in Case No. 9155 an update to its Rider E-MD—EmPOWER MD Charge. The Commission accepted the tariff revisions on January 22, 2015. While the tariff does not specify whether capacity DRIPE will be included in the incentive, Attachment 9 to the December filing is entitled "Pepco DLC Bonus Workpapers" and describes the use of "Capacity Price Mitigation" (i.e., capacity DRIPE) in computing PEPCo's bonus for direct load control.

Attachment 9 describes the MEA-utility 50%-of-VRR methodology, including the 20% annual decay in the DRIPE effect. The attachment estimates capacity-DRIPE benefits to PEPCo Maryland customers of $1,017,777 for part of 2013 and $2,238,511 for 2014, representing 14% and 20% of total benefits for those years. Since PEPCo claims a bonus equal to 5% of benefits, the capacity DRIPE results incentives of about $160,000 for this 19-month period.

Q: How does PEPCo justify its estimates of capacity DRIPE benefits?

A: Attachment 9 says simply that PEPCo used "Maryland Energy Administration ("MEA") EmPOWER 2014 adopted process." As I explain in Section III.B.1 above, PEPCo's explanation of the justification of the 50% VRR method is internally inconsistent and ultimately meaningless. Despite the high level of detail provided in other portions of the filing, Attachment 9 does not provide the full derivation of the claimed mitigation value, including the slope of the demand curve assumed for each delivery year and the PEPCo Maryland load affected by the capacity price.[9]

Q: How does BGE use capacity DRIPE in its incentive computation?

A: Unlike PEPCo, BGE does not file its incentive computations in its EmPOWER docket, but as separate undocketed tariff revisions. The latest such filing is styled “Supplement No. 556 to PSC Md. E-6: Rider 2—Electric Efficiency Charge, Rider 15—Demand Response Service Charge and Rider 26—Peak Time Rebate Charge,” filed November 13 2014, and logged as ML 160394 on the Commission’s maillog system.[10] Attachment 3, at unnumbered 24, shows the derivation of the VRR estimate of capacity DRIPE. The capacity DRIPE that BGE claims is greater than the program’s annual capacity and energy revenue in each year since 2012. The incentive BGE claims on the price mitigation in 2013–2015 is almost $2 million.

Q: Other than the use of the grossly overstated VRR capacity DRIPE methodology, have you identified any other problems with BGE’s computation of capacity price mitigation?

A: Yes. The computation ignores any decay of DRIPE. Of the 345 MW of load-control capacity BGE claimed for 2013/14, 261 MW were installed in 2010/11 or earlier, so the 20% annual decay assumed in the MEA-utility capacity DRIPE

---

[9]Some of the limited information provided appears to be incorrect. Attachment 9 reports that PEPCo’s load-control program was credited with installed capacity (ICAP) of 131.6 MW in 2013/14 and 157 MW in 2014/15, which PEPCo equates to unforced capacity (UCAP) of 124.1 MW in 2013/14 and 175.2 MW in 2014/15. These values imply that the ratio of ICAP to UCAP was 1.06 in 2013/14 and 0.90 in 2014/15. Since the RPM parameters changed little between these auctions, at least one of these values is almost certainly incorrect.

[10]An errata filing was provided on December 8 2014 as ML 161248.

projection would substantially reduce the estimated price reduction in the period for which BGE was claiming an incentive (2013 through 2015).

Q: What should the Commission do with respect to the computation of capacity DRIPE in the shareholder incentives for the load-control programs?

A: I understand that the Commission has approved the current shareholder-incentive requests, which are based in part on the above capacity DRIPE calculations, and that this is not the appropriate forum to implement changes to the shareholder incentive computations. However, subject to the Commission's decision in this matter, I would recommend that these computations be revised to be consistent with the slopes I compute in Section VI.A, below, and the decay assumptions accepted by both PEPCo and BGE for the energy-efficiency computations. The mechanism for implementing those changes may be different for the two utilities, since BGE's incentive is embedded in its Rider 15 tariff, while PEPCo's tariff does not describe the incentive computation (or even specify the inclusion of price mitigation).

IV. Improving Estimates of Energy DRIPE

Q: You discuss in Section III.A problems in the energy DRIPE values, due to the use of a production-costing model. Are there other problems with the DRIPE values used in those analyses?

A: Yes. Not all energy purchased for retail load will be affected by reductions in market prices in the short term, due to (1) existing full-service contracts for the Standard Offer Service ("SOS") offered by the investor-owned utilities and SMECo's longer-term energy procurements, and (2) contracts between customers and competitive electric suppliers.

According to the Public Service Commission's Report to the Governor and the General Assembly on the Status of Standard Offer Service, the Development of Competition, and the Transition of Standard Offer Service to Default Service (January 8, 2014, at 7), 52.2% of Maryland peak load was served by competitive electricity suppliers at the end of 2013.

Contracting arrangements vary among the classes. Residential rates are usually fixed for a year or less, while many large consumers have multi-year fixed-price contracts with retail power marketers, up to about three years. Typically, a residential customer served by a marketer will have about six months left on its contract and energy DRIPE in the first year will affect only half the electricity bill. For small C&I the contract period is probably longer, perhaps one year. If the average contract for the mid- and large-C&I groups is three years, only one third of the first year DRIPE effect will be realized, and then two thirds of the second year effect, and the full effect in the third year.

For the customers on standard offer, the length of time before energy DRIPE can affect retail prices in each class is very different. The IOUs procure standard offer service (SOS) for residential and small commercial classes each spring and fall, for overlapping two-year periods starting six months in the future, with each procurement covering about 25% of the load. Following a procurement, the prices are 100% fixed for the next year, 75% and 50% fixed for the next two half-years (averaging about 63% fixed in the second year), and 25% fixed in the first half of the following year (or an average of 12.5% in year three). For mid-sized C&I customers, the procurements are for just three months, conducted shortly before the beginning of delivery, so only about two months (or 16% of the first year) are fixed on average. Any large C&I customers served by the utility are charged spot-market prices and are unhedged.

The Southern Maryland Electric Cooperative does not procure full-requirement contracts, but instead builds up a portfolio of capacity and energy contracts of varying duration (and varying shape, for the energy component), supplemented by short-term and spot purchases and sales and payments for other PJM services (e.g., ancillary service). I have not found any detailed information on SMECo's contracting strategy. If SMECo is heavily hedged in the long-term market, load reductions (from any utility's energy-efficiency program) may not affect SMECo's customers for several years. If SMECo plans for purchasing a significant amount of energy on the spot market, energy-efficiency savings may affect those costs almost immediately.

From the percentage of load on competitive service, the assumptions above regarding the duration of competitive contract prices and utility-service prices (or alternative reasonable assumptions), and the breakdown of sales among the rate classes (which we do not have readily available) are straightforward in order to estimate the percentage of total load covered by fixed prices in each of the first few years following an energy-efficiency investment. That portion of the load should be excluded from the DRIPE computation, unless there is good reason to believe that the prices charged by wholesale suppliers to the utilities, and prices charged by retail suppliers directly to the consumers, reflect planned reductions years in advance.

V. Capacity Markets within Maryland

Q: What issues do you address in this section?

A: I discuss the factors that influence whether the various LDAs that cover various parts of Maryland will separate, the likelihood of separation, and probable long-term average-capacity-price trends.

Q: What factors determine whether the various LDAs clear at the same price, or separate?

A: Whether the MAAC zone (and its sub-LDAs) separate from the RTO in the future depends on the demand-supply balances in the RTO and in MAAC, which in turn depends on the following factors:

- relative rates of load growth in MAAC and rest-of-RTO. The PJM Load Forecast Report (revised February 2014) projects 0.8% annual growth in PJM RTO summer peak and 0.6% in MAAC,
- relative rates of energy-efficiency development in MAAC and rest-of-RTO,
- retirements in the rest-of-RTO zone,
- retirements in MAAC,
- additions in RTO and MAAC,
- transmission additions. The probability of zones and LDAs separating falls as transmission is added between various combinations of those areas.

Q: What is the prospect for retirements outside MAAC affecting future capacity prices?

A: The rest-of-RTO LDA cleared a large amount of coal capacity in the 2017/18 BRA, and some fraction of that remaining capacity may drop out of the capacity market in future auctions.[11] Much of the pressure on coal plants comes from existing and pending environmental-compliance requirements, including MATS, CSAPR, the regional-haze rule, cooling-water regulations under §316(b) of the Clean Water Act, effluent limits, and the carbon-emissions limits under the Clean Power Plan.

[11]This process is well under way. From 2016/17 to 2017/18, PJM reported 7,150 MW of reductions in generation capacity bids outside MAAC, apparently excluding the plants (like the Illinois nuclear units) that bid and did not clear (2017/2018 RPM Base Residual Auction Results at 22–23 and Table 7A).

The generation affiliates of the major Ohio utilities have asked the Ohio PUC to subsidize almost 7,000 MW of older plants (3,200 MW of FirstEnergy coal and nuclear, 3,500 MW of AEP coal, and 240 MW of Duke coal) with life-of-unit firm contracts to cover the difference between the plants' costs and market revenues. Part of their justification for the requests is that the capacity is vulnerable to retirement if the proposals are rejected.[12]

In 2013, the Brattle Group forecasted that about 12,000 to 18,000 MW of coal capacity in non-MAAC PJM would be retired in the 2014–2018 period.[13] Since PJM reports that only about 8,700 MW of coal was retired (or is scheduled for retirement) outside of MAAC from late 2014 to May 2018 (the period covered by past BRAs), 3,000 to 9,000 MW of coal capacity remains at risk for delivery years 2018/19 and beyond.

In addition to the environmental regulations, PJM is in the process of changing its capacity-market rules to impose penalties on generators for not being on line when needed and to reward them for producing capacity above their contract level. Since some of those capacity needs occur outside the peak hours, units that are not always on line and take hours to ramp up to full output (most oil- and gas-fueled steam plants, and some coal plants) are likely to reduce their capacity bids, so that the penalties when they are off line will be balanced by the rewards when they are operating during a capacity requirement. The resulting lower MW bids may cause some of these units to retire entirely. Both reduced bids and retirements will tend to drive up capacity prices.

---

[12] www.midwestenergynews.com/2014/08/14/firstenergy-touts-benefits-of-plan-critics-decry-as-bailout/

[13] www.brattle.com/system/publications/pdfs/000/004/966/original/Coal_Plant_Retirements_-_Feedback_Effects_on_Wholesale_Electricity_Prices.pdf

The 3,700 MW of Exelon nuclear units in the PJM portion of Illinois that did not clear in the 2017/18 BRA may be kept on line by Illinois legislative or regulatory initiatives (e.g., some form of credit for CO_2 compliance, increased transmission to relieve low local energy prices) and return in the 2018/19 BRA. On the other hand, the low wind-related LMPs that Exelon blames for the poor economics of Quad Cities and Byron may spread to other Exelon nuclear units in Illinois. The energy-price effects of the additional wind energy may be offset by additional transmission within western PJM and surrounding MISO regions.

Q: What is the prospect for retirements in MAAC affecting future capacity prices?

A: In November 2013, NRG requested permission from PJM to deactivate the coal-fired units at Chalk Point (667 MW) and Dickerson (537 MW) by May 2017, which was granted. In early May 2014, NRG delayed those retirements to May 2018, keeping them in the 2017/18 auction, in which they cleared. While NRG might decide to keep these units operating for a few more years, they face considerable environmental compliance costs. The Brattle Group forecast retirements of as much as 2,500 MW of coal-fired capacity in MAAC remain at risk (only about 20% of the non-MAAC retirements). About 1,000 MW of coal retirements are reflected in the completed BRAs, and the Chalk Point and Dickerson retirements would total another 1,200 MW, leaving only about 300 MW at risk (under 10% of the non-MAAC value).

Oyster Creek, which did not clear in the 2017/18 BRA, is under a consent decree that will require its retirement by 2019 for compliance with the Clean Water Act, so it is probably permanently out of the capacity market. Other MAAC nuclear capacity is not as vulnerable to concentrations of renewables as are the Illinois nuclear units.

Q: Would retirement of another 1,000 to 2,000 MW of MAAC capacity have caused the MAAC price to separate from the rest of the RTO in the 2017/18 BRA?

A: No. The PJM sensitivity analysis for the 2017/18 BRA found that MAAC would not have separated from the RTO, even if 3,000 MW or 6,000 MW of low-cost MAAC resources were retired. Depending on which zones the capacity were from, the higher level could cause EMAAC capacity prices to rise above the level of the RTO and MAAC.[14]

Q: How much additional capacity in the rest of the RTO would have caused the RTO price to fall below the MAAC price in the 2017/18 BRA?

A: The PJM sensitivity analysis for the 2017/18 BRA found that adding 3,000 MW of low-cost resources outside of MAAC would have reduced capacity prices in both MAAC and the Rest of RTO zone, but would not have caused the prices to separate from one another. Prices would separate if 6,000 MW were added in non-MAAC areas and if none were added in MAAC. That would be an extreme outcome, given that 59% of new PJM generation has been in MAAC in the last three BRAs, or 1.5 times the generation added outside MAAC.

Q: How are additions in RTO and MAAC likely to affect whether their prices separate?

A: Recent capacity additions indicate that large amounts of generation can be added in both MAAC and the rest of the RTO, at similar prices. The PJM auction reports provide a limited breakdown of new generation units bid and cleared, by location (EMAAC, MAAC and total RTO) and technology (including

[14] The PJM analysis assumed about half the MAAC capacity reductions would be in EMAAC.

combined-cycle, combustion turbine, and seven other categories).[15] The reports do not break out the amounts that cleared in individual zones (such as ATSI and PSEG) that cleared at prices higher than the surrounding LDA. Nonetheless, the reports give me enough information to compute the minimum gas-fired capacity that cleared at the MAAC and rest-of-RTO prices, by taking the worst case: all the EMAAC capacity was at the higher PSEG zonal price, all the EMAAC capacity was gas, and all the new rest-of-RTO generation in 2016/17 cleared at the higher ATSI zonal price.[16]

Table 3 summarizes these data for each of the last three capacity auctions, along with the annual capacity price for each year and each of these three LDAs. In addition to upgrades, reactivations, renewables, and other new resources, at least 8,000 MW of combined-cycles and combustion turbines were added in the areas that cleared at $120/MW-day or less in the last two auctions, of which 3,800 MW was in MAAC.

Table 3: Summary of New Generation Clearing PJM Auctions

	2015/16	2016/17	2017/18
Locations of Generation Added (MW)			
EMAAC	2,314	59	1,746
MAAC	2,991	1,555	4,418
Total RTO	4,899	4,282	5,927
Rest of MAAC	677	1,496	2,672
Rest of RTO	1,908	2,727	1,510
Type of New Generation Added (MW)			
CT/GT	1,383	171	131

[15]2017/2018 RPM Base Residual Auction Results, PJM, 6/18/2014, Tables 2A and 8, and comparable tables from the 2015/16 and 2016/17. www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2017-2018-base-residual-auction-report.ashx

[16]The ATSI zone did not separate in 2017/18, and the 2015/16 ATSI price was so much higher than the other LDA prices that I could derive no useful information on the prices at which new generation cleared.

CC	5,915	4,995	5,010
Other	362	149	248
Total	7,659	5,314	5,389
Minimum Gas outside EMAAC but in:			
MAAC	315	1,347	2,424
RTO		4,074	3,933
Max Clearing Price($/MW-Day)			
MAAC	$167	$119	$120
Rest of RTO	Note a	$114	$120

Note a: ATSI price was six times rest of western PJM; no useful breakout possible.

If MAAC continues to add capacity at those prices, its capacity price is even less unlikely to separate from the rest-of-RTO price.

Q: What do you conclude about the relationship of future capacity prices between Potomac Edison and the other Maryland utilities?

A: While some combinations of load growth, resource additions and retirements could cause prices to separate, the most likely outcome of future BRAs is that all the Maryland utilities will clear as part of the RTO, although it is also possible that the MAAC would separate from the RTO in some auctions, raising the MAAC price and reducing the RTO price.

As a result, the avoided capacity price is likely to be consistent across Maryland in most years, and the capacity DRIPE values are likely to be identical for all Maryland utilities.

VI. Estimating Capacity DRIPE for Maryland Utilities

Q: How should capacity DRIPE be estimated for Maryland utilities?

A: I have discussed the steps in the computation of capacity DRIPE in Sections III.B and V. In this section, I will summarize what I believe are the best current approaches for the following four issues:

- potential price effects and scope,
- utility bidding strategies in the BRAs,
- reduction for hedged supply,
- market response and DRIPE decay.

A. Potential Price Effect and Scope

Q: What do you mean by potential price effect and scope?

A: I mean the total capacity price suppression that would occur if not for three offsetting factors (savings that are not bid into the first applicable BRA, the effect of existing contracts, and market response) and the amount of load that benefits from the price reduction. The scope of the effect is closely related to the manner in which the potential price effect is estimated.

Q: How should these factors be computed?

A: I have used two approaches. The first is to use the New Equilibrium approach that MEA developed (but then ignored) in the VRR Curve Capacity DRIPE document. The second relies on the sensitivity analyses that PJM releases after every BRA.

Q: How would capacity DRIPE developed with the New Equilibrium approach differ from the values that the utilities used?

A: The New Equilibrium estimates the actual price shift that would occur with additional energy-efficiency load reductions, rather than the arbitrary and incorrect value used by the utilities, but the application of this corrected value would be very similar to the computation that MEA developed for its 50% VRR estimate. Table 4 compares the values for the two approaches from the MEA exhibit, with a couple adjustments. First, I recomputed the New Equilibrium slopes for 2017/18, which MEA had assumed would be the same as 2016/17.

Second, I reflect the reality that MAAC is part of the RTO, so load and supply changes in MAAC also affect prices in the rest-of-RTO zone.[17]

In the 2017/18 BRA, the Maryland portions of MAAC did not separate from the rest of the RTO, so the load reductions in the rest of RTO (including Potomac Edison) would affect prices paid throughout Maryland and load reductions in MAAC moves prices in MAAC and RTO along the RTO equilibrium slope.

Table 4: New Equilibrium and 50% VRR Potential Capacity DRIPE

	2014/15	2015/16	2016/17	2017/18	Average 16/17 & 17/18
RTO Slopes ($/MW-Day/MW)					
VRR B-C	$0.0532	$0.0455	$0.0460	$0.0493	
VRR 50%	$0.0266	$0.0227	$0.0230	$0.0246	
New Equilibrium	$0.0163	$0.0129	$0.0070	$0.0071	$0.0070
MAAC Slopes ($/MW-Day/MW)					
VRR B-C	$0.0773	$0.0862	$0.0885	$0.1012	
VRR 50%	$0.0386	$0.0431	$0.0443	$0.0506	
New Equilibrium	$0.0338	$0.0266	$0.0167	$0.0071	$0.0167
MD UCAP Obligation (MW)					
RTO (PE)	1,601	1,636	1,669	1,685	1,677
MAAC (Other utilities)	13,435	13,331	13,433	13,266	13,350
MEA DRIPE Values ($/MW-day)					
PE @ RTO	$42.59	$37.20	$38.39	$41.53	
MD MAAC Load @ MAAC	$519.10	$574.79	$594.75	$671.60	
Equilibrium DRIPE Values ($/MW-day)					
PE @ RTO	$26.04	$21.04	$11.66	$11.98	
MD MAAC Load @ MAAC	$453.95	$354.40	$224.98	$94.27	
Total PE (PE + MAAC in 17/18)	$26.04	$21.04	$11.66	$106.25	$58.96
Total MAAC (MAAC + PE)	$479.99	$375.44	$236.64	$106.25	$171.45
Equilibrium Value as % MEA					
PE	61%	57%	30%	29%	
MD MAAC	92%	65%	40%	35%	

[17]The rest-of-RTO price is determined by total demand and supply in the RTO, not just the residual outside constrained LDAs.

Q: Is this a comprehensive analysis of the potential capacity-price effects, prior to the three adjustments you listed above?

A: No. Table 4 accounts for effects of rest-of-RTO load on MAAC price only in 2017/18. As I discuss below, PJM has found that increasing resources in the rest of the RTO reduces prices in MAAC. The data in the MEA exhibit do not provide any insight into the magnitude of these effects.

Q: Do the PJM sensitivity analyses provide a more-comprehensive view of the capacity DRIPE effects than the MEA analysis?

A: Yes. MEA's analysis is a commendable effort to use the available information on the supply and VRR curves (up to the final error in using the 50% VRR slope, rather than the New Equilibrium slope). Nonetheless it relies on visual estimation of the supply slope from a graph that PJM manipulates to obscure individual bids. MEA's approach also cannot directly estimate the effect of rest-of-RTO load and resources on MAAC prices.

The sensitivity analyses represent PJM's hypothetical reruns of the BRA, adding or subtracting various amounts of low-price capacity in one or more LDAs.[18] The results should reflect all the complexities of the operation of the PJM capacity auctions, including the differing VRRs in the modeled zones and LDAs. Table 5 shows the average $/MW-day change in price in various LDAs for adding or subtracting a MW of supply in each of four zones.[19] The top section shows the average of additions and reductions of capacity over three years in which MAAC prices separated from the RTO price (averaging a total of

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

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

six slopes), while the bottom section shows the results from 2017/18, when MAAC cleared at the RTO price and PJM did not model EMAAC and SWMAAC separately in the sensitivity analysis.

Table 5: Summary of PJM Sensitivity Analyses

	Price Change ($/MW-day) from 1-MW change in LDA in			
	RTO	MAAC	EMAAC	SWMAAC
2014/15 to 2016/17				
Rest of RTO	−0.0084	−0.0018		
Western MAAC (MAAC in 2014/15)	−0.0029	−0.0151		
EMAAC	−0.0014		−0.0124	–0.0099
SWMAAC	−0.0063		–0.0171	−0.0173
2017/18				
Rest of RTO	−0.0073	−0.0073		
MAAC	−0.0064	−0.0064		

Table 6: Potential DRIPE from PJM Sensitivity Scenario Studies

	2014/15	2015/16	2016/17	2017/18	Average 16/17 & 17/18
Change in RTO Price ($/MW-Day/MW)					
per MW in RTO (RTO/RTO)	$0.0080	$0.0102	$0.0090	$0.0087	
Per MW in MAAC (RTO/MAAC)	$0.0042	$0.0028	$0.0015	$0.0069	
Change in MAAC Price ($/MW-Day/MW)					
per MW in RTO (MAAC/RTO)	$0.0040	$0.0025	$0.0005	$0.0064	
Per MW in MAAC (MAAC/MAAC)	$0.0146	$0.0149	$0.0163	$0.0069	
MD UCAP Obligation (MW)					
RTO (PE)	1,601	1,636	1,669	1,685	1,677
MAAC (Other utilities)	13,435	13,331	13,433	13,266	13,350
Equilibrium DRIPE Values ($/MW-day)					
PE @ RTO/RTO + Others @ MAAC/RTO	$67.11	$50.32	$21.12	$99.17	$60.14
Others @ MAAC/MAAC +PE @ RTO/MAAC	$202.61	$202.98	$221.01	$103.25	$162.13

The annual sensitivity scenario results are provided in Exhibit PLC-3.

Q: How do these results compare to the New Equilibrium slopes estimated by MEA?

A: The RTO slopes for 2014/15 through 2016/17 in MEA's analysis average $0.012/MW-day per MW of resource change, or about 40% more than the value estimated in the PJM sensitivities. For SWMAAC, the MEA average was

$0.0257/MW-day per MW, about 50% higher than the PJM results. The western MAAC and EMAAC values are even lower.[20] No information is available on the 2017/18 supply curve to drive the MEA estimates; using the 2016/17 supply curve and MEA's method, I estimated a 2017/18 slope of $0.0071/MW-day per MW in the RTO, which includes MAAC; that value is close the PJM sensitivity results for the RTO, and only exceeds the PJM sensitivity result for MAAC by about 10%.

Q: What values should the utilities use for the capacity DRIPE slope and potential $/MW-day benefit per MW of energy-efficiency additions?

A: For 2014/15 through 2017/18, capacity that was bid into the auctions should be valued at the slopes in Table 5 (or Exhibit PLC-3, to separate the three auctions). After 2017/18, I recommend using the 2017/18 slopes from Table 5, or if there is reason to believe that the MAAC price may separate from the RTO, the average of the 2016/17 and 2017/18 slopes. In addition, the post-2017/18 DRIPE value should escalate with expected load growth and possibly with general inflation.[21] In all years, the DRIPE effect should be recognized for all Maryland load, although Potomac Edison's effect on the other utilities is sometimes lower than the MAAC utilities' effects on prices in MAAC, and vice versa.

[20]Since some of the resource changes that PJM models in EMAAC are in the PSEG load pocket, the EMAAC are probably not representative of changes in DPL's service territory, which generally follows SWMAAC rather than PSEG.

[21]Whether capacity DRIPE is driven by inflation is an open question. The costs of new resources will rise, but their net energy revenues may also rise, reducing the net cost that new resources must recover from the capacity market. The cost of capacity may rise over time, but the slope of the supply curve may flatten.

B. Timing of the Initial Price Effect

Q: How should the phase-in of DRIPE be structured to represent the timing of capacity bids for the energy-efficiency programs?

A: I have not been able to completely sort out the data on the utilities' demand reduction (cumulative and annual, net and gross, calendar year and delivery year) and on their reported energy-efficiency capacity bids (new and cumulative, reflecting PJM's four-year limit on claiming energy-efficiency savings). However, BGE's response to OPC DR 3-2 in Case No. 9154 (9/30/2014) indicates that it has bid in 50% to 58% of the total "capabilities of its energy efficiency (EE) measures in delivery years 2015-16, 2016-17 and 2017-18." I attach this response as Exhibit PLC-4.

The utilities should provide consistent, transparent data that would allow the Commission to review and approve their strategy for bidding capacity into the BRAs, including the following information:

- the load reduction the utility experienced or expects by the beginning of each capacity delivery year,
- the portion of that load reduction counted for four years and hence expiring prior to delivery year,
- the portion of the load reduction that is not eligible under the PJM-approved Measurement & Verification protocols,
- the amount bid and cleared in the BRA for that delivery year.

Q: What do you propose the utilities assume about the timing of their bidding until they can compile the analysis you describe above?

A: It appears from the BGE response that it bids about 50% of its eligible energy-efficiency demand reductions, which would support an incremental phase-in such as the following:

- 12% bid in the installation year (since most installations in any calendar year will not count as resources in the BRA or affect prices until the next year),
- 26% bid in the second year,
- 12% bid in the third year,
- 12.5% reflected in the load forecast for the fourth year (as I discuss in Section III.B),
- 25% reflected in the load forecast for the fifth year, and
- 12.5% reflected in the load forecast for the sixth year, for a total effect of 100% for measures that last that long.

These estimates are subject to revision if the utilities can produce better evidence.

C. *Reduction for Hedged Supply*

Q: What reduction in DRIPE to reflect the hedging of supply do you suggest?

A: As I note in Section 2, it is difficult to determine the extent to which customers not taking standard offer supply are hedged, since the contract terms are not generally public. Pending better information, I suggest assuming the following percentages of hedged supply:

- 60% in the installation year,
- 35% in the second year,
- 10% in the third year,
- zero thereafter.

The unhedged portion in the first year would be the sum of the percentage of load on contracts indexed to actual prices, the prorated load that switches to a new contract in the year, and the portion of standard-offer load that is repriced during the year.

D. Decay of the Price Effect

Q: Why would the price effect of a load reduction decline over time?

A: The DRIPE effect is gradually offset by market responses over time. Lower prices may result in some additional retail load. The lower prices may also result in retirement of some generation units and demand response projects that are then removed from the supply curve for future auctions, as well as possibly delaying proposed resources unit they are canceled.

Q: How do you suggest reflecting that decline?

A: Modeling these effects in any rigorous manner is very challenging. The MEA assumed that "DRIPE benefits will be decayed over a period of 10 years, decreasing at a 20% compound rate in the first five years and straight line for the remaining five years" (EmPOWER 2015–2017 Cost Effectiveness Framework, August 18, 2014, at 10) That seems reasonable.

E. Summary of Capacity DRIPE Recommendation

Q: What would be the result of the assumptions you discuss above, regarding capacity DRIPE?

A: Table 7 summarizes the development of DRIPE for measures installed in MAAC in 2015, based on the values I discuss above.

Table 7: Summary of DRIPE Estimate for 2015 Installations in MAAC
($/MW-day)

			Bidding Strategy							
			50% bid in			*50% reflected in forecasts*				
	Potential DRIPE	**Hedged**	2015	2016	2017	2019	2020	2021	*Decay from 1st year reflected*	*Net DRIPE*
	a	*b*	*c*	*d*	*e*	*f*	*g*	*h*	*i*	*j*
2015	$202.61	60%	12%						100%	$9.85
2016	$202.98	35%	12%	26%					80%	$46.73
2017	$221.01	10%	12%	26%	12%				64%	$80.53
2018	$103.25		12%	26%	12%				51%	$33.44
2019	$162.25		12%	26%	12%	12.5%			41%	$62.32
2020	$166.59		12%	26%	12%	12.5%	25%		33%	$92.84
2021	$170.37		12%	26%	12%	12.5%	25%	12.5%	25%	$96.91
2022	$174.30		12%	26%	12%	12.5%	25%	12.5%	16%	$77.89
2023	$177.77		12%	26%	12%	12.5%	25%	12.5%	8%	$60.64
2024	$182.03		12%	26%	12%	12.5%	25%	12.5%	0%	$45.20
2025	$186.39		12%	26%	12%	12.5%	25%	12.5%		$32.39
2026	$190.77		12%	26%	12%	12.5%	25%	12.5%		$23.44
2027	$194.81		12%	26%	12%	12.5%	25%	12.5%		$15.96
2028	$198.67		12%	26%	12%	12.5%	25%	12.5%		$8.14
2029	$202.96		12%	26%	12%	12.5%	25%	12.5%		$2.08
PV 2015 @ 5.5%										$486.24

The net DRIPE is the potential DRIPE, times 1 minus the hedged percentage, times the sum of the six columns *c–h,* each multiplied by the decay factor in column *i.* The decay associated with each of the six columns of the bidding strategy starts with the first year that there is a value in the column, so column *i* shifts one row down for column *d*, five rows for column *h.*

Table 8 shows the net DRIPE values for each installation date. The columns identify the LDA and installation year, and each row represents the capacity DRIPE value in a given calendar year, for measures that last that long.

Table 8: Summary of DRIPE Values ($/MW-Day)

	2015 Installation		2016 Installation		2017 Installation	
	RTO/PE	MAAC	RTO/PE	MAAC	RTO/PE	MAAC
2015	$1.39	$9.63				
2016	$10.29	$50.60	$1.39	$9.63		
2017	$8.30	$80.53	$10.29	$50.60	$1.39	$9.63
2018	$37.41	$30.59	$8.30	$80.53	$10.29	$50.60
2019	$28.87	$60.61	$37.41	$30.59	$8.30	$80.53
2020	$45.87	$90.29	$28.87	$60.61	$37.41	$30.59
2021	$48.78	$94.26	$45.87	$90.29	$28.87	$60.61
2022	$39.56	$75.76	$48.78	$94.26	$45.87	$90.29
2023	$31.33	$58.98	$39.56	$75.76	$48.78	$94.26
2024	$24.07	$43.96	$31.33	$58.98	$39.56	$75.76
2025	$17.78	$31.50	$24.07	$43.96	$31.33	$58.98
2026	$12.49	$22.80	$17.78	$31.50	$24.07	$43.96
2027	$8.51	$15.52	$12.49	$22.80	$17.78	$31.50
2028	$4.34	$7.91	$8.51	$15.52	$12.49	$22.80
2029	$1.11	$2.02	$4.34	$7.91	$8.51	$15.52
2030			$1.11	$2.02	$4.34	$7.91
2031					$1.11	$2.02

For example, the net DRIPE value for a BGE measure installed in 2016 and reducing load by one MW would be $94.26 per day in 2021.

F. Capacity Price

Q: What capacity price would you expect in future capacity auctions?

A: Table 3 above (at 34), shows that both MAAC and the rest of the RTO were able to add thousands of megawatts of gas generation at prices less than $120/MW-day, even in a period of significant environmentally driven retirements, totaling about 12,000 MW in 2016/17 and 2017/18. While the real cost of building new gas units might increase over time, as the best sites are used and developers move on to less desirable sites, there seem to be many potential sites for new gas-fired units in both MAAC and the rest-of-RTO. Furthermore, more sites (with appropriate zoning, transmission access, cooling water, and other infrastructure) will open up as coal plants are retired.

The annual costs of new units are likely to rise somewhat as the Federal Reserve Bank allows interest rates to rise. And the price will undoubtedly fluctuate from year to year, depending on such factors as the rate at which renewables and energy-efficiency resources are developed, the timing of new construction, and the extent to which last-minute retirements create previously unforeseen capacity needs. But I do not see why the market-clearing price in MAAC would rise 80% in real terms from 2017 to 2030, as MEA projects.

Pending further analysis, I suggest that the avoided capacity cost be limited to 2% real escalation from the 2017/18 market-clearing price.

Q: Does this conclude your testimony?

A: Yes.

Exhibit PLC-1

PAUL L. CHERNICK

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

SUMMARY OF PROFESSIONAL EXPERIENCE

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

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

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

EDUCATION

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

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

HONORS

Chi Epsilon (Civil Engineering)

Tau Beta Pi (Engineering)

Sigma Xi (Research)

Institute Award, Institute of Public Utilities, 1981.

PUBLICATIONS

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

"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), in *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

"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

"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." 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.

"Increasing Market Share Through Energy Efficiency." 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.

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, Boston Edison Company; 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.

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. Testimony eventually withdrawn due to delay in case.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

    Profit margin calculations, including methodology, interest rates.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

    Profit margin calculations, including methodology and implementation.

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

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

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

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

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

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

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

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

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

Construction schedule and cost of completing Millstone Unit 3.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

53. **Ill. Commerce Commission** 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** Docket 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. **Vermont 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. Commerce Commission** Docket 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, and 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. Utility Regulatory Commission;** 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, and 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. 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. Utilities Commission** 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.). 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. Utilities Commission** 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.

DSM 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. Commerce Commission** 92-0268, Electric-energy plan for Commonwealth Edison; City of Chicago. Direct testimony, 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. Utilities Commission 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 Formal 917, 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.

DSM 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. Utilities Commission E-2, Sub 669. December 1995.

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

136. Arizona Commerce Commission 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; 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; Massachusetts Attorney General. July 1996.

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

142. **Mass.** **DPU** 96-60; Massachusetts Attorney General. Direct testimony, July 1996; surrebuttal, August 1996.

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

143. **Md.** **PSC** 8725; 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** Case 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.

Power-supply arrangements between APS's 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 streetlighting, 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. Direct, 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 Case 03-2144-EL-ATA; Ohio Edison, Cleveland Electric, and Toledo Edison Cos. rates and transition charges; Green Mountain Energy Co. Direct 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 Cases 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. Utilities Commission** Project No. 3698388, British Columbia Hydro resource-acquisition plan; British Columbia Sustainable Energy Association and Sierra Club of Canada BC Chapter. Direct, 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. Direct 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 Testimony, 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** Case 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. Utility Regulatory Commission** Cause Nos. 42943 and 43046; Vectren Energy DSM proceedings; Citizens Action Coalition. Direct, June 2006.

Rate decoupling and energy-efficiency goals.

217. **Penn.** **PUC** Docket No. 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** Docket No. 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.

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 since August 2006.

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 Case No. 05-1444-GA-UNC; recovery of conservation costs, decoupling, and rate-adjustment mechanisms for Vectren Energy Delivery of Ohio; Ohio Consumers' Counsel. Direct, 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** Case 06-G-1332; Consolidated Edison Rates and Regulations; City of New York. Direct, 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. Direct, May 2007

Direct assignment of distribution costs to streetlighting. Cost causation and cost allocation. Minimum-system and zero-intercept classification.

226. **Conn.** **DPUC** Docket 07-04-24; Review of capacity contracts under Energy Independence Act; Connecticut Office of Consumer Counsel, Joint Direct Testimony 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** Case 07-E-0524; Consolidated Edison electric rates; City of New York. Direct, 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. Direct, 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. Direct, 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. Direct, 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. Direct, 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** Case 08-E-0596; Consolidated Edison electric rates; City of New York. Direct, 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. Direct, 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. Direct, November 2008.

Marginal costs. Rate design. Time-of-use rates.

237. **Md. PSC** 9036; Columbia Gas rates; Maryland Office of People's Counsel. Direct, 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. Review Board** Matter No. 01439; Nova Scotia Power DSM and cost recovery, Nova Scotia Consumer Advocate. May 2009.

Recovery of demand-side-management costs and lost revenue.

240. **N. S. Review Board** Matter No. 0496; proposed biomass project, Nova Scotia Consumer Advocate. June 2009.

Procedural, planning, and risk issues with proposed power-purchase contract. Biomass price index. Nova Scotia Power's management of other renewable contracts.

241. **Conn. Siting Council** 370A; Connecticut Light & Power transmission projects; Connecticut Office of Consumer Counsel. Direct, July 2009.

Need for transmission projects. Modeling of transmission system. Realistic modeling of operator responses to contingencies

242. **Mass. DPU** 09-39; NGrid rates, Mass. Department of Energy Resources. August 2009.

Revenue-decoupling mechanism. Automatic rate adjustments.

243. **Utah PSC** Docket No. 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** Docket No. 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** Docket No. R-2009-2139884; Philadelphia Gas Works energy efficiency and cost recovery; Philadelphia Gas Works. Direct, December 2009.

Avoided gas costs. Recovery of efficiency-program costs and lost revenues. Rate impacts of DSM.

246. **B.C. Utilities Commission** Project No. 3698573; British Columbia Hydro rates; British Columbia Sustainable Energy Association and Sierra Club British Columbia. Direct, February 2010.

Rate design and energy efficiency.

247. **Ark. PSC** Docket No. 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** Docket No. 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** Docket No. 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** Matter No. 02961; Port Hawkesbury biomass project; Nova Scotia Consumer Advocate. Direct, 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. Direct, 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, 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; N.S. Consumer Advocate. Direct, October 2010.

Cost allocation. Cost of capital. Effect on rates of growth in sales.

256. **Man. PUB** Case No. 17/10, Manitoba Hydro rates; Resource Conservation Manitoba and Time to Respect Earth's Ecosystem. Direct, December 2010

Revenue-allocation and rate design. DSM program.

257. **N.S. UARB** Matter No. 03665; Nova Scotia Power depreciation rates; N.S. Consumer Advocate. Direct, February 2011.

Depreciation and rates.

258. **New Orleans City Council** No. UD-08-02; Entergy IRP rules; Alliance for Affordable Energy. Direct, December 2010

Integrated resource planning: Purpose, screening, cost recovery, and generation planning.

259. **N.S. UARB** Matter No. 03632; Renewable-Energy Community-Based Feed-in Tariffs; N.S. Consumer Advocate. Direct, March 2011.

Cost of projects. Rate effects of feed-in tariffs. Consideration of community in computing costs.

260. **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.

261. **Utah** **PSC** Docket No. 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.

262. **N.S.** **UARB** Matter No. 04104; Nova Scotia Power general rate application; N.S. 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.

263. **N.S.** **UARB** Matter No. 04175; Load-retention tariff; N.S. Consumer Advocate. August 2011.

Marginal cost of serving very large industrial electric loads; risk, incentives and rate design.

264. **Ark.** **PSC** Docket No. 10-101-R; Rulemaking re self-directed energy efficiency for large customer; National Audubon Society and Audubon Arkansas. Testimony July 2011.

Energy efficiency.

265. **Okla. Corporation Commission** Cause No. 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.

266. **Nevada** **PUC** Docket No. 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.

267. **La.** **PSC** Docket 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.

268. **Okla. Corporation Commission** Cause No. 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

269. **Ky. PSC** Case No. 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.

270. **N.S. UARB** Matter No. 04819; Demand-side-management plan of Efficiency Nova Scotia; N.S. Consumer Advocate. May 2012.

Avoided costs. Allocation of costs. Reporting of bill effects.

271. **Kansas CC** Docket No. 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.

272. **N.S. UARB** Matter No. 04862; Port Hawksbury load-retention mechanism; N.S. 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.

273. **Utah PSC** Docket No. 11-035-200; Rocky Mountain Power Rates; Utah OCC. June 2012.

Cost allocation. Estimation of marginal customer costs.

274. **Ark. PSC** Docket No. 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.

275. **U.S. EPA** Docket 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.

276. **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.

277. **Vt. PSB** Docket No. 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.

278. **Man. PUB** 2012–13 GRA, Manitoba Hydro rates; Green Action Centre. November 2012

Estimation of marginal costs. Fuel switching.

279. **N.S. UARB** Matter No. M05339; Capital Plan of Nova Scotia Power; N.S. Consumer Advocate. January 2013.

Economic and financial modeling of investment. Treatment of AFUDC.

280. **N.S. UARB** Matter No. M05416; South Canoe wind project of Nova Scotia Power; N.S. Consumer Advocate. January 2013.

Revenue requirements. Allocation of tax benefits. Ratemaking.

281. **N.S. UARB** Docket No. NSPI-P-892; Depreciation Rates of Nova Scotia Power; N.S. Consumer Advocate. April 2013.

Steam-plant lives and removal costs.

282. **N.S. UARB** Matter No. 05419; Maritime Link cost-recovery regulations; N.S. Consumer Advocate. Direct, April 2013; Joint Supplemental (with Seth Parker), November 2013.

Load Forecast. Cost effectiveness of proposed project.

283. **Ont. Energy Board** 2012-0451/0433/0074; Enbridge Gas GTA 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** Matter No. M05092; Tidal energy feed-in-tariff rate; N.S. 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** Matter No. M05473; Nova Scotia Power 2013 cost-of-service study; N.S. Consumer Advocate. October 2013.

Cost-allocation and rate design.

286. **B.C. Utilities Commission** Projects Nos. 3698715 & 3698719; Performance-based ratemaking plan for FortisBC companies, British Columbia Sustainable Energy Association and Sierra Club British Columbia. Joint testimony 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. **Man. PUB** 2014 NFAT, Fuel-switching, DSM, and wind; Green Action Centre. Evidence (with Wesley Stevens) February 2014.

Potential for fuel switching, DSM, and wind to meet future demand.

288. **Utah PSC** Docket 13-035-184; Rocky Mountain Power Rates; Utah OCC. May 2014.

Class cost allocation. Classification and allocation of generation plant and purchased power. Principles of cost-causation. Design of backup rates.

289. **Minn. PSC** Docket No. E002/GR-13-868, OAH Docket No. 68-2500-31182; 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.

290. **Cal. PUC** Rulemaking 12-06-013, electric rates and rate structures; Natural Resources Defense Council. Direct, September 2014.

Redesigning residential rates to simplify tier structure while maintaining efficiency and conservation incentives. Effect of marginal price on energy consumption. Realisitic modeling of consumer price response. Benefits of minimizing customer charges.

291. **Md. PSC** Case No. 9361, proposed Exelon-PEPCo merger; 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.

292. **N.S. UARB** Matter No. M06514; 2015 capital-expenditure plan of Nova Scotia Power; N.S. 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.

ACRONYMS AND INITIALISMS

ASLRB	Atomic Safety and Licensing Board
BEP	Board of Environmental Protection
BPU	Board of Public Utilities
BRC	Board of Regulatory Commissioners
DER	Department of Environmental Regulation
DPS	Department of Public Service
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
PSC	Public Service Commission
PUC	Public Utility Commission
PUB	Public Utilities Board
PURPA	Public Utility Regulatory Policy Act
SCC	State Corporation Commission
UARB	Utility and Review Board
USAEE	U.S. Association of Energy Economists
UTC	Utilities and Transportation Commission

PLC 1/29/2015

Exhibit PLC-2

Equivalence of Adding Energy-Efficiency Capacity and Reducing Load

Paul Chernick
Resource Insight, Inc.

Query: Is it true that adding a given amount of capacity to a linear Supply function will result in the same price as subtracting that capacity from a linear Demand function?

For the supply curve (the price that suppliers will charge for supplying *x* MW):

$$S_0 = b_S + m_s x \ ,$$

and the demand curve (the price set by the VRR curve for *x* MW):

$$D_0 = b_D - m_D x$$

Note that m_D is the magnitude of the slope with the direction noted in the preceding negative sign.

A positive horizontal shift of α MW to the supply curve shifts the supply y-intercept downward. A negative horizontal shift of the demand curve shifts the demand y-intercept downward as well.

The horizontal shift of the supply curve shifts its y-intercept:

$$b_{supply\ shifted} = b_S - m_S \alpha$$

The Supply function, horizontally shifted + α units, equals:

$$S_{shifted} = m_s x + (b_S - m_s \alpha) = m_s (x - \alpha) + b_S$$

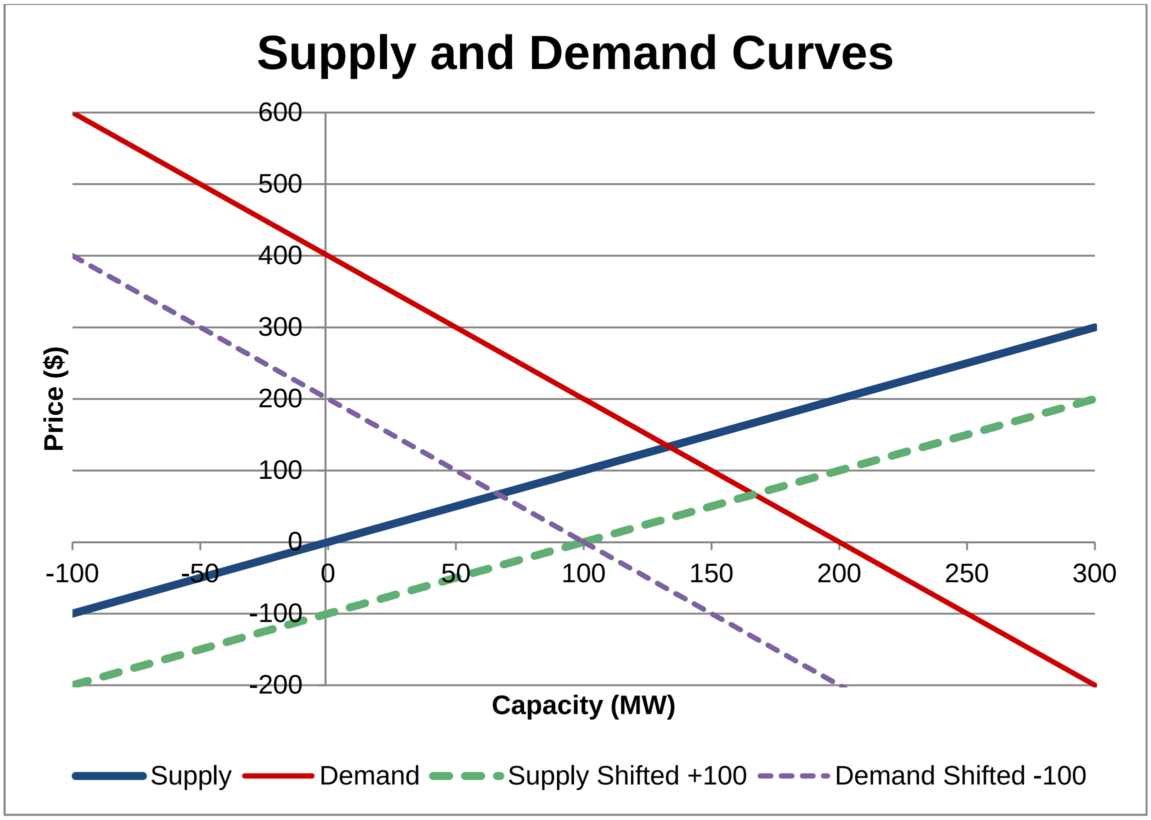
Similarly, applying a negative horizontal shift of α units to the demand curve shifts its y-intercept:

$$b_{demand\ shifted} = b_D - m_D \alpha$$

The shifted Demand function equals:

$$D_{shifted} = b_D - m_D (\alpha + x)$$

The rationale for the shift in the y-intercept for each function can be seen in the numeric example graph below. The supply function is S = 1x + 0 and the demand function is D = 400–2x. Adding +100MW at $0 shifts the supply curve down by $100 \times m_S = 100$. Subtracting 100W from the demand curve likewise shifts that curve down by $100 \times m_p = 200$.



For the intersection of the supply curve S_0 with the VRR $D_{shifted}$ and the intersection of $S_{shifted}$ with D_0, we find the equilibrium quantity x^* and then substitute that into either half to get $Price^*$

For $\boldsymbol{S_0 = D_{shifted}}$

$$m_s x + b_S = b_D - m_D(\alpha + x)$$

Solve for x

$$x^* = \frac{b_D - b_s + m_s \alpha}{m_s + m_D}$$

$$Substitute\ x^*\ into\ S_0\ or\ D_{shifted}\ to\ get\ Price$$

$$Price^* = b_D - m_D\left(\frac{b_D - b_s + m_s\alpha}{m_s + m_D}\right)$$

For $S_{shifted} = D_0$

$$m_s(x - \alpha) + b_S = b_D - m_D x$$

$$x^* = \frac{b_D - b_s - m_D\alpha}{m_s + m_D}$$

$$Substitute\ x^*\ into\ S_{shifted}\ or\ D_0\ to\ get\ Price$$

$$Price^* = b_D - m_D\alpha - m_D\left(\frac{b_D - b_s - m_s\alpha}{m_s + m_D}\right)$$

Our question is whether these two prices are the same.

$$b_D - m_D\left(\frac{b_D - b_s + m_s\alpha}{m_s + m_D}\right) \stackrel{?}{=} b_D - m_D\alpha - m_D\left(\frac{b_D - b_s - m_s\alpha}{m_s + m_D}\right)$$

$To\ both\ sides, subtract\ b_D, divide\ by\left(\frac{m_s+m_D}{m_D}\right)\ and\ multiply\ by -1$

$$b_D - b_s + m_s\alpha \stackrel{?}{=} \alpha(m_s + m_D) + b_D - b_s - m_D\alpha$$

Simplifying,

$$m_S\alpha + m_D\alpha = m_S\alpha + m_D\alpha$$

$$Q.E.D.$$

Exhibit PLC-3:
Results of PJM Sensitivity Studies

2014/15 BRA

Supply Change in	Delta Supply	RTO	MAAC	EMAAC	SWMAAC	Separation Changes in Scenario
		Price change ($/MW-day/MW) in				
RTO	4000	-0.0068	-0.0027			
RTO	8000	-0.0089	-0.0013			
RTO	-4000	-0.0049	-0.0023			MAAC and RTO Merge
RTO	-8000	-0.0112	-0.0099			MAAC and RTO Merge
MAAC	2000	-0.0064	-0.0117	*-0.0015*		MAAC and RTO Merge; EMAAC Separates
MAAC	4000	-0.0061	-0.0087	*-0.0008*		MAAC and RTO Merge; EMAAC Separates
MAAC	-2000	-0.0023	-0.0168	*-0.0168*		
MAAC	-4000	-0.0023	-0.0212	*-0.0212*		
EMAAC	1000	-0.0010	-0.0115	-0.0115	-0.0115	MAAC and RTO Merge
EMAAC	2000	-0.0060	-0.0113	-0.0113	-0.0113	MAAC and RTO Merge
EMAAC	-1000	-0.0008	-0.0002	-0.0002	-0.0002	
EMAAC	-2000	-0.0018	-0.0099	*-0.0283*	-0.0099	EMAAC Separates
SWMAAC	500	-0.0020	-0.0070	*-0.0062*	-0.0070	EMAAC Separates
SWMAAC	-500	-0.0252	-0.0165	*-0.0165*	-0.0165	MAAC and RTO Merge; EMAAC Separates
Average effect of Supply change in						
RTO	±4,000	-0.0059	-0.0025			
MAAC	±2,000	-0.0043	-0.0142	-0.0092		
EMAAC	±1,000	-0.0009		-0.0058	-0.0058	
SWMAAC	±500	-0.0136		-0.0114	-0.0118	

N.B.: Negative Slopes indicate Increasing Price as MWs or reduced Prices as MWs rise

Source File Name: Sensitivity Scenario Analysis Results (XLS)

Source Location: http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2014-2015-sensitivity-scenario-analysis-results.ashx

2015/16 BRA

Supply Change in	Delta Supply	Price change ($/MW-day/MW) in RTO	MAAC	EMAAC	SWMAAC	Notes
rest of RTO	6000	-0.0089	*0.0013*			
rest of RTO	-6000	-0.0115	-0.0063			MAAC and RTO Merge
rest of MAAC	3000	-0.0039	-0.0144			MAAC and RTO Merge
rest of MAAC	-3000	-0.0017	*-0.0154*			
rest of EMAAC	1500	-0.0018	-0.0108	-0.0108	-0.0108	
rest of EMAAC	-1500	-0.0020	-0.0217	-0.0217	-0.0217	
rest of SWMAAC	750	-0.0027	-0.0170	-0.0170	-0.0170	
rest of SWMAAC	-750	-0.0027	-0.0367	-0.0367	-0.0367	
Average effect of Supply change in						
rest of RTO		-0.0102	-0.0025			
rest of MAAC		-0.0028	-0.0149			
rest of EMAAC		-0.0019		-0.0163	-0.0163	
rest of SWMAAC		-0.0027		-0.0269	-0.0269	

N.B.: Negative Slopes indicate Increasing Price as MWs or reduced Prices as MWs rise

Source File Name: Sensitivity Scenario Analysis Results (XLS)

Source Location: http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/sensitivity-scenario-analysis-results.ashx

2016/17 BRA

Price change ($/MW-day/MW) in

Supply Change in	Delta Supply	RTO	MAAC	EMAAC	SWMAAC	Notes
rest of RTO	6000	-0.0072	0.0000			
rest of RTO	-6000	-0.0109	-0.0009			MAAC and RTO Merge
rest of MAAC	3000	-0.0023	-0.0222	*-0.0040*	-0.0222	MAAC and RTO Merge; EMAAC Separates
rest of MAAC	-3000	-0.0008	-0.0103	-0.0103	-0.0103	
rest of EMAAC	1500	-0.0010	-0.0114	-0.0114	-0.0114	
rest of EMAAC	-1500	-0.0015	-0.0036	*-0.0188*	-0.0036	EMAAC Separates
SWMAAC	750	-0.0020	-0.0122	-0.0122	-0.0122	
SWMAAC	-750	-0.0030	-0.0140	-0.0140	-0.0140	
Average effect of Supply change in						
rest of RTO		-0.0090	-0.0005			
rest of MAAC		-0.0015	-0.0163	-0.0071		
rest of EMAAC		-0.0013	-0.0075	-0.0151	-0.0075	
SWMAAC		-0.0025	-0.0131	-0.0131	-0.0131	

N.B.: Negative Slopes indicate Increasing Price as MWs or reduced Prices as MWs rise

Source File Name: Sensitivity Scenario Analysis Results (XLS)

Source Location: http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2016-2017-sensitivity-scenario-analysis-results.ashx

2017/18 BRA Price change ($/MW-day) in

Supply Change in	Delta Supply	RTO	MAAC	EMAAC	SWMAAC	Notes
rest of RTO	-3000	-0.0102	-0.0102			
rest of RTO	3000	-0.0044	-0.0044			
rest of RTO	-6000	-0.0081	-0.0081			
rest of RTO	6000	-0.0122	*-0.0028*			MAAC Separates from RTO
MAAC	-3000	-0.0094	-0.0094	-0.0094		
MAAC	3000	-0.0035	-0.0035	-0.0035		
MAAC	-6000	-0.0081	-0.0081	*-0.0199*		EMAAC Separates from RTO
MAAC	6000	-0.0067	-0.0067	-0.0067		
Average effect of Supply change in						
rest of RTO	±3,000	-0.0073	-0.0073			
MAAC	±3,000	-0.0064	-0.0064			
EMAAC						
SWMAAC						

N.B.: Negative Slopes indicate Increasing Price as MWs Decrease or reduced Prices as MWs rise

Source File Name: Sensitivity Scenario Analysis Results (XLS)

Source Location: http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2017-2018-bra-scenario-analysis.ashx

Definitions:

Rest of RTO excludes MAAC, ATSI (in delivery years 2015/16, 2016/17)

rest of MAAC Excludes EMAAC, SWMAAC

rest of EMAAC Excludes PSEG (in delivery years 2015/16, 2016/17)

Notes:

Price slope in italics indicate that the LDA separated from the surrounding LDA (MAAC from RTO, EMAAC from MAAC, SWMAAC from MAAC) in the base case.

Averages use the smallest increment/decrement pair for each LDA

Exhibit PLC-4:
BGE Response to OPC DR 3-2

OPCDR3-2

Plan Attachment 7, pdf p. 235, indicates that 50% of 2015 installations are assumed to be cleared in BRA 2015/16, with the other 50% affecting capacity prices starting in 2016/17 or 2017/18.

a) Did BGE apply these assumptions to all measures and programs, or did it treat some programs as being in the cleared 50% and others in the non-cleared 50%?

b) Please provide the basis for BGE's estimate that 50% of its capacity savings currently for 2015, 2016 and 2017 cleared in the BRA for those years.

RESPONSE:

a) All programs were treated similarly.

b) BGE's capabilities of its energy efficiency (EE) measures in delivery years 2015-16, 2016-17 and 2017-18 are estimated to be 202 MW, 208 MW and 210 MW, respectively. BGE offered and cleared 100 MW of EE capability in the 2012 BRA, 120 MW in the 2013 BRA and 119 MW in the 2014 BRA, or 50%, 58% and 57%, respectively, of estimated capability.

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that on this 30th day of January, 2015, the foregoing "Comments" of the Maryland Office of People's Counsel for Case Nos. 9153-9157 and 9362 was either hand-delivered, e-mailed or mailed first-class, postage prepaid to all parties of record to this proceeding.

/electronic signature/
Gregory T. Simmons
Assistant People's Counsel

Maryland Office of People's Counsel
6 St. Paul Street, Suite 2102
Baltimore, Maryland 21202
(410) 767-8150