BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Petition of Philadelphia Gas Works for Approval of Demand-Side Management Plan for FY 2016-2020; and, Philadelphia Gas Works Universal Service and Energy Conservation Plan for 2014-2016 52 Pa Code § 62.4 – Request for Waivers	:	Docket No. P-2014-2459362

DIRECT TESTIMONY

OF

PAUL L. CHERNICK

RESOURCE INSIGHT, INC.

On Behalf of

Philadelphia Gas Works

Topics Addressed:

Development of Avoided Costs
Conservation Adjustment Mechanism

May 4, 2015

{L0593855.1} 300025-51

TABLE OF CONTENTS

TABLE OF EXHIBITS

I. INTRODUCTION AND BACKGROUND

Q. 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. PLEASE 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, conservation program design, cost recovery for utility efficiency programs, the valuation of environmental externalities from energy production and use, 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 approximately two hundred times on utility issues before various regulatory, legislative, and judicial bodies, including utility regulators in 24 states and three Canadian provinces, and two Federal agencies.

Q. HAVE YOU TESTIFIED PREVIOUSLY BEFORE THIS COMMISSION?

A. Yes. I testified in the following dockets:

- Docket R-842651, a Pennsylvania Power and Light rate case, on the need for, and operating costs and rate effects of, the Susquehanna-2 nuclear plant, on behalf of the Pennsylvania Consumer Advocate.
- Docket R-850152, a Philadelphia Electric Rate Case, on rate effects of Limerick 1, on behalf of the Utility Users Committee and University of Pennsylvania.
- Docket R-850290, on auxiliary rates for Philadelphia Electric, on behalf of the University of Pennsylvania and Amtrak.
- Docket I-900005, R-901880, on electric-utility DSM and DSM-cost recovery, for the Pennsylvania Energy Office.
- Docket No. 00061346, on real-time pricing for Duquesne Lighting, on behalf of PennFuture.
- Docket No. R-00061366, et al., rate-transition-plan proceedings of Metropolitan Edison and Pennsylvania Electric, on real-time and time-dependent pricing, on behalf of PennFuture.
- Docket No. R-2009-2139884, on the first five-year DSM plan of Philadelphia Gas Works.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. My testimony is submitted on behalf of Philadelphia Gas Works ("PGW").

Q. PLEASE SUMMARIZE YOUR EXPERIENCE IN THE DEVELOPMENT OF AVOIDED COSTS.

A. I have developed or modified estimates of electric avoided costs for numerous electric utilities; many of these estimates are listed in my resume. I estimated statewide avoided costs for Vermont in 1997, and portions of the regional avoided generation costs for all of New England for a consortium of utilities in 1999, 2001, 2007, 2009, 2011, and 2013.[1] I also described the process of deriving avoided costs in a report to the Pennsylvania Energy Office in 1993.[2] I have developed gas avoided costs for the following utilities:

- Boston Gas (now part of National Grid) in the late 1980s and early 1990s,
- Washington Gas Light in the 1990s,
- New England consortium reports (above) in 1999 and 2001 (plus some aspects of more recent reports, including 2013),
- two reports for NYSERDA ("Natural Gas Energy Efficiency Resource Development Potential in Con Edison Service Area" and "Natural Gas Energy Efficiency Resource Development Potential in New York") in 2006,
- New York's energy-efficiency rulemaking in 2009,

---

1 These are, respectively, "Avoided Energy Supply Costs for Demand-Side Management in Massachusetts" (1999), "Updated Avoided Energy Supply Costs for Demand-Side Screening in New England" (2001), "Avoided Energy Supply Costs in New England: 2007 Final Report" (2007), and "Avoided Energy Supply Costs in New England: 2009 Final Report" (2009), "Avoided Energy Supply Costs in New England: 2011 Report" (2011), and "Avoided Energy Supply Costs in New England: 2013 Report" (2013), all for the Avoided-Energy-Supply-Component Study Group, c/o National Grid Company (Northborough, Massachusetts).

2 That work was in "Qualifying the Benefits of Demand Management," the fifth volume of the five-volume *From Here to Efficiency: Securing Demand-Management Resources* published in 1992 and 1993 by the Pennsylvania Energy Office.

- Peoples Gas Company (Illinois) in 2009,
- PGW annually since 2009,
- Enbridge Gas in 2013,
- FortisBC in 2013.

Q. PLEASE SUMMARIZE YOUR EXPERIENCE IN THE PLANNING AND PROMOTION OF ENERGY-EFFICIENCY PROGRAMS.

A. I have testified on demand-side-management potential, economics, and program design in approximately 65 proceedings since 1980. In the 1990s I participated in several collaborative efforts among utilities, consumer advocates, and other parties, including those for PEPCo, BG&E, Delmarva Power, Potomac Edison, Washington Gas Light, Central Vermont Public Service, Vermont Gas, and NYSEG. More recently, I have participated in collaboratives related to Con Edison's gas- and electricity-efficiency programs, New York statewide program rules and objectives, and energy-efficiency collaboratives in Maryland and Illinois.

Q. PLEASE SUMMARIZE YOUR EXPERIENCE REGARDING RECOVERY OF UTILITY ENERGY-EFFICIENCY PROGRAM COSTS, ASSOCIATED REVENUE LOSSES, AND PERFORMANCE INCENTIVES.

A. I first proposed a combined revenue-stabilization and conservation-funding mechanism in testimony on alternatives to the Seabrook nuclear power plant before the New Hampshire Public Utilities Commission in Docket No. DE1-312 in October 1982. My qualifications list a number of subsequent engagements related to ratemaking for energy efficiency, including recovery of direct costs, lost revenue and performance incentives.

I have supported broader revenue stabilization than proposed by the utilities in some cases (e.g., in Ontario), and proposed modifications to utility decoupling proposals in other situations (e.g., for Con Edison's electric sales, Vectren's Indiana gas territories).

I have also worked on issues of cost recovery in collaborative efforts among utilities, consumer advocates, and other parties, including Con Edison's gas revenue-per-customer decoupling collaborative.

I have developed lost-revenue and performance-incentive mechanisms for consumer advocates (including the Maryland Office of People's Counsel, the Ohio Office of Consumer Counsel, and the City of New York) and other parties since the early 1990s.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to describe the derivation of PGW's avoided gas costs and support PGW's proposal for the recovery of lost distribution margin through the Conservation Adjustment Mechanism ("CAM") resulting from the proposed DSM II plan described in the testimony of PGW witness Theodore Love. Throughout the process of preparing PGW's filing in this proceeding, and in developing this testimony, I have worked closely with Mr. Love.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. I recommend that the Commission approve the use of the avoided costs developed in my testimony for screening PGW's energy-efficiency plan, the inclusion of lost margin in the CAM and incentives for superior performance in delivering energy-efficiency services, as proposed by Mr. Love.

II. DEVELOPMENT OF AVOIDED COSTS

(A) Avoided Gas Costs

Q. DID YOU DEVELOP THE AVOIDED GAS COSTS USED IN THE ECONOMIC SCREENING OF PGW'S PROPOSED DSM II PLAN?

A. Yes.

Q. PLEASE DESCRIBE YOUR APPROACH.

A. The purpose of avoided costs is to estimate the benefit to consumers of reduced energy usage. The major benefit is the reduction of the quantity of gas required to serve customer loads and of the associated pipeline and storage capacity required to deliver the gas to the PGW citygate at the times customers require it. This benefit does not necessarily equal the rate paid by the customer to the utility or a natural-gas supplier in a particular month. The market price of gas varies daily, while the utility (or supplier) may pay all year round for capacity resources that serve customer loads only a few days in a typical year. The costs resulting from customer gas consumption thus vary with load shape. For customers using gas supplied by PGW, all the costs of gas used by customers will flow through to customers and all the costs saved from energy efficiency will similarly flow through to customers. Customers served by natural-gas suppliers may pay a contract rate in the short term, but those rates are likely to be adjusted over time to reflect the costs of serving the customer's actual load.

I outline my approach in this testimony. Exhibit PLC-2 presents the derivation of avoided gas costs in greater detail.

Q. HOW DID YOU PROJECT THE COST OF GAS OR THE BENEFIT OF REDUCED GAS CONSUMPTION?

A. A detailed explanation can be found in Exhibit PLC-2, but I'll outline the projection here. My estimate of the avoided cost of natural gas for PGW's customers comprises the following components:

- *Supply-area commodity costs:* The price of gas delivered at Henry Hub, for normal-year weather.

- *Commodity delivery costs:* marginal pipeline and storage charges for gas delivered from Henry Hub to PGW's citygate in a normal year.
- *Peaking capacity:* The costs of storage capacity to cover the difference between normal and design-peak conditions.
- *Avoided costs of environmental compliance.*
- *The effect of load reductions* on the price of gas paid by Pennsylvania gas and electric customers.

Q. HOW DID YOU PROJECT THE SUPPLY-AREA COMMODITY COSTS?

A. I began with the monthly forward prices for gas at Henry Hub as posted on April 20 2014 for the period September 2015 through August 2027.[3] That period includes PGW's September–August fiscal years from 2015/16 (FY2016) through 2025/26 (FY2026). In the longer term, no forward market prices are available, so I relied on the Energy Information Administration's 2014 Annual Energy Outlook (AEO), released May 7 2014.[4] Since the 2026 AEO price differed from the 2026 forward price, I blended the two projections together for 2019–2026. Beyond FY2026, I escalated the Henry Hub gas price at the real 2027-2014 average escalation rate forecast by AEO, plus the 2% inflation rate used across PGW's analysis.

For baseload efficiency measures, which save the same amount of energy every day, the avoided supply-area commodity cost is simply the average of the gas prices across months, weighted by the number of days in the month. For heating measures, I

---

3 Prices were posted only through December 2027.

4 The 2015 AEO report was released on April 14 2015, too late to be used in preparation of the filing. The changes in natural gas prices from AEO 2014 to AEO 2015 for 15–20 year lives in the period of the second five-year plan do not appear to be substantial.

assumed that the savings would be distributed across months in proportion to normal monthly heating degree days. Within each month with significant heating load, I estimated the historical ratio of prices weighted by normal heating degree days to the simple average of the prices.

Q. HOW DID YOU PROJECT THE DELIVERY PRICES?

A. The delivery price has several components. First, I reduced the Henry Hub price by 10¢/Dth to reflect the lower cost at South Texas, the starting point for much of PGW's gas contracts.

Second, I added in the costs of delivering gas in the off-peak months of April through October from South Texas to PGW's citygate in the M-3 zone of the Texas Eastern (TETCo) pipeline. I assume that contract capacity is not a binding constraint in those months and set the delivery charge at Texas Eastern's variable commodity rate ($0.1105/Dth). In addition, the delivery costs include Texas Eastern's 5.8% tariff transport fuel charge.

Third, for December through February, I assumed that the marginal source of supply is the Texas Eastern CDS rate, which includes the following costs:

- the demand charges (from South Texas, into storage, and back out of storage to Zone M-3) of $21.88/Dth-month for 12 months, spread over 115 days of storage, or an average of $2.28/Dth;[5]
- about $0.51/Dth for volumetric charges (the South Texas–M-3 charges, plus space, injection, and withdrawal charges in seasonal storage);

---

[5] I distributed the costs of the CDS capacity in proportion to the average heating degrees per day for each month, to recognize the higher value of the capacity at high-load periods. The resulting allocations ranged from $3.25/Dth in January to $2.35 in March and November.

- fuel use of about 11.7%.

Fourth, I recognized that November and March contain a mix of cold and milder days. While all the days in December through February fall in the coldest 115 days on the PGW system in a normal winter, only six days in November and nineteen days in March do so. Accordingly, I attributed the CDS cost to those days and the lower cost of the TETCo transportation rate ($17.06/Dth-month) to the other days in each month, with the capacity costs allocated evenly over the heating months. The transportation capacity is equivalent to $1.35/Dth, plus the commodity costs, and fuel use reflecting the mix of transport and storage in each month.

The annual delivery charge for baseload measures are the average of the delivered gas prices across months, weighted by the number of days in the month, while the annual delivery charge for heating measures is the average of the month prices, weighted by heating degree days.

Q. OTHER THAN COMMODITY DELIVERED TO THE CITYGATE IN A NORMAL-WEATHER YEAR, DOES ENERGY EFFICIENCY ALLOW PGW TO AVOID ANY OTHER COSTS?

A. Yes. In addition to providing gas to meet normal weather, PGW must provide enough reserve capacity to meet loads under design conditions, including both a design day with 65 heating degree days and a design winter with heating loads approximately 19.4% greater than normal. I estimated the cost of that reserve as the price of PGW's contracts supporting its most expensive storage supply (the SS-1B contract) times the percentage increase in heating load between normal and design winters. I took the fixed cost of the peaking supply as $80.37/Dth-year. The reserve capacity needed to serve heating load on a design day is about 0.75% of the heating usage (about 34°F reserve spread over 4,613

HDD), so maintaining the reserve costs about $0.62/Dth in FY2016. Baseload does not increase under design conditions, and thus has no peaking-reserve cost.

Q. DO ENERGY EFFICIENCY AND CONSERVATION INVESTMENT HAVE OTHER BENEFITS, BEYOND THOSE YOU HAVE QUANTIFIED?

A. Yes. PGW's energy-efficiency programs and resulting reductions in gas load would have several positive effects including the following beneficial functions:

- Create local jobs for local businesses in implementing the programs, from distributing equipment and materials to installation and inspections.
- Reduce wholesale-market gas prices, particularly in the Northeast. While this is a small price effect per ccf, it has that effect over large amounts of retail sales and the large amounts of electric energy that is priced at the marginal costs of gas-fired generators.
- Improve customer comfort.
- Potentially improve PGW cash flow.
- Improve customer ability to pay.
- Leave customers with additional cash to be spent in Philadelphia, stimulating the local economy.
- Provide a model for energy-efficiency programs for other Pennsylvania gas utilities, which would directly benefit the customers of those utilities and multiply the market-price benefits to consumers.
- Reduce carbon emissions, the social cost of those emissions, and the cost to consumers of compliance with likely future carbon limits.

The benefits of reducing market prices and carbon emissions, addressed in Sections II(B) and II(C) below, have been quantified as additional avoided costs and provided within alternative TRC figures for consideration in DSM Phase I. In Phase II, PGW proposes to include these components within the primary avoided costs and TRC calculations. Philadelphia Gas Works has not quantified the other effects listed above, but they are all properly included in the benefits of an energy-efficiency and conservation program.

Where loads are growing, energy efficiency also frees up distribution capacity that allows the utility to avoid some system upgrades. Most of PGW's system has experienced declining loads and hence needs no capacity-related upgrades. Indeed, PGW's miles of distribution mains have declined slightly but consistently since 2009. Nonetheless, there may be areas in which PGW will eventually require increased delivery capacity due to local growth. In those situations, PGW may be able to defer or avoid distribution upgrades.

(B) Wholesale Price Suppression

Q. HOW DOES GAS CONSERVATION AFFECT THE PRICE OF GAS PURCHASED FOR THE LOAD THAT REMAINS AFTER THE ENERGY-EFFICIENCY INVESTMENTS?

A. Reduced gas consumption reduces both the market price of natural gas in North America and the market price of transportation to deliver gas to the citygate. The following sections summarize my analyses of these effects; details are provided in Appendix 6.1 of Exhibit TML-4.

1) Supply Market Effects on PGW Gas Bills

Q. HOW MUCH DOES THE PRICE OF GAS SUPPLY RESPOND TO THE CHANGES IN GAS CONSUMPTION?

A. To examine this question, I reviewed the literature and found that a number of analyses estimated that a 1% reduction in US gas consumption would reduce gas prices by about

1%–3%. I updated these analyses by using the results of the sensitivity analyses that the EIA ran for the 2012 and 2014 AEOs.

As shown in Appendix 6.1 of Exhibit TML-4, plots of the changes in price against demand in the EIA sensitivity results are remarkably linear, with the small changes in the early years clustered near the origin and the large changes in later years closer to the ends of the trend line. The 2012 AEO results imply that every quad (billion Dth) decrease in annual gas consumption results in a $0.632/Dth decrease in Henry Hub gas price (in 2010$).[6]

Q. HOW DOES THAT COEFFICIENT OF PRICE CHANGE PER CONSERVED DTH TRANSLATE TO A SAVINGS TO PENNSYLVANIA CONSUMERS AS A RESULT OF CONSERVED GAS?

A. The effect of this change in price on consumer bills is the product of the $0.632/Dth per quad times the annual gas use by the relevant consumers. Since PGW's end-use gas sendout for FY2014 was about 78 million Dth, the potential effect on PGW gas end users' gas supply bill of one Dth reduction in gas consumption is

$$(\$0.632 \times 10^{-9}/\text{MMBtu}) \times (0.078 \times 10^{9}\ \text{MMBtu}) = \$0.05/\text{Dth saved.}$$

Similarly, PECo has gas deliveries of about 90 million Dth, so every Dth reduction in usage would save PECo gas customers another $0.036/Dth. The statewide gas deliveries to customers are about 582 million Dth, producing statewide benefits of $0.233/Dth.

[6] The AEO data do not appear to show any significant decay in the price-reduction values over time.

2) Gas-Supply Market Effects on Electric Bills

Q. DO THESE REDUCTIONS IN SUPPLY-AREA GAS PRICES REDUCE ELECTRIC PRICES?

A. Yes. Natural gas set the market price in PJM about 33% of the time in calendar 2013; that value appears to be rising as coal plants are retired. Unfortunately, PJM does not report the marginal supply for various parts of the power pool, so we cannot tell how much of the marginal energy serving the area around Philadelphia is from gas. However, the value is almost certainly higher than the system-wide average.[7]

When gas sets the market electric price, reductions in gas prices reduce market prices for electric energy. Assuming an average heat rate of 9.5 Dth/MWh, the savings to PECo customers (many of which are also PGW customers) from a Dth reduction in gas use would be

$$(\$0.632\times10^{-9}/\text{MMBtu}) \times (9.5\ \text{MMBtu/MWh}) \times 39.7 \times 10^{6}\ \text{MWh} \times 33\% = \$0.08/\text{MMBtu}$$

For all of Pennsylvania, with deliveries of about 146.3 million MWh, lower gas supply prices would save customers statewide about $0.29 for every MMBtu saved.

3) Transportation Market Effects on Electric and Gas-Transport Bills

Q. HOW DO LOAD REDUCTIONS AFFECT THE COSTS OF GAS TRANSPORTATION?

A. Reductions in gas loads reduce the market-price difference (or basis) from supply areas to consumption areas. Most gas distribution companies, including PGW, purchase almost all their gas transportation services under fixed-price regulated contracts (such as those described in Section II(A)) and are thus not affected by market basis. But most electric

[7] Compared to Pennsylvania, areas to the west have more coal, which makes up about half the marginal supply overall, and wind, which makes up 5% of the margin.

generators in PJM (and other restructured regions) purchase all their gas transportation at market prices. Reducing gas transportation costs will tend to reduce electric market prices, in the periods for which gas sets the market price. Most interruptible gas transportation customers also probably purchase their gas on the spot markets.

Q. HOW DID YOU ESTIMATE THE MAGNITUDE OF THE EFFECT OF REDUCED GAS USAGE ON MARKET TRANSPORTATION PRICES?

A. I examined the historical relationship between monthly consumption in the Northeast and basis from Henry Hub to the TETCo M-3 zone, which is a major pricing point for generation in eastern Pennsylvania, New Jersey, and surrounding regions. I defined the Northeast as including the states served by the M-3 zone and those downstream: Pennsylvania, New Jersey, New York, Massachusetts, Rhode Island, Connecticut and New Hampshire.[8] As shown in Appendix 6.1 of Exhibit TML-4, I found that the reducing winter gas consumption by one quad reduces basis by $0.021/MMBtu.

Q. HOW DOES THIS REDUCTION IN TRANSPORTATION PRICE AFFECT ELECTRIC PRICES?

A. As shown in Appendix 6.1 of Exhibit TML-4, the benefit for PECo customers would be about $0.20/MMBtu of saved space-heating gas and $0.09/MMBtu for baseload savings. The Pennsylvania utilities in the MAAC region (PECo, PPL, Penelec, MetEd and UGI), collectively use about three times as much energy in the four winter months (December to March) as does PECo, so the statewide savings would be about three times the PECo savings. Since most electric customers are supplied through fixed-price contracts that last several months or a few years, the price reduction will flow through to customers with a delay averaging about a year.

---

[8] Only eastern Pennsylvania should be included in this area, since western Pennsylvania is upstream of Zone M-3, but I do not have monthly data on gas consumption for areas smaller than states.

For PGW's interruptible transport customers, each saved Dth saves about \$0.042/MMBtu of saved space-heating gas and \$0.019/MMBtu of saved baseload gas, at the end of a three-year phase-in period (assuming that customers have fixed-price transportation contracts averaging three years in duration).[9]

Since less congestion on the pipelines may slow expansion of lines, it is reasonable to phase out the basis price effect over a few years, starting in 2020.

(C) Avoided Environmental Costs

Q. WHAT ENVIRONMENTAL COSTS DID YOU ESTIMATE FOR INCLUSION IN PGW'S ECONOMIC EVALUATION OF ITS ENERGY-EFFICIENCY PROGRAMS?

A. A: I compiled information on the following costs:

- Likely future carbon prices that may be applied economy-wide, including on gas burned by PGW's customers.
- The social cost of carbon emissions.
- The health costs of NOx and SO2 emissions from power plants.

These costs, per unit of pollution emitted, and the value of avoiding the emissions per Dth or MWh conserved, are described in detail in Appendix 6.1 of Exhibit TML-4.

Q. HOW DID YOU ESTIMATE THE INTERNALIZED COSTS OF CARBON CHARGES?

A. I relied on the 2013 summary of carbon-pricing forecasts from Synapse Energy Economics, as described in Appendix 6.1 of Exhibit TML-4. I used Synapse's mid-case projection of carbon allowance prices, which assumes that carbon caps take effect in 2020, starting at \$15/ton in 2012 dollars, rising linearly to \$37.5 in 2030 and \$60 in 2040.

[9] If the customers pay market prices on a daily, weekly, or monthly basis, or if fixed-price contract durations are shorter than three years, the phase-in period would be shorter or non-existent.

I multiplied that price by emissions of 118 pounds of CO_2 per Dth, to get internalized carbon prices of $0.92/Dth in 2020; $2.30/Dth in 2030 and $3.68/Dth in 2040.

Q. HOW DID YOU ESTIMATE THE SOCIAL COSTS OF CARBON EMISSIONS?

A. I relied on the Federal Interagency Working Group mid-range results, using a 3% real discount rate, as shown in Appendix 6.1 of Exhibit TML-4. Those costs (in 2007 dollars) start at about $38/ton in 2015, rising to $43 in 2020, $52 in 2030, and $62/ton in 2040.

Converting to a cost per Dth of gas burned, the costs are $2.42/Dth in 2015, $2.53 in 2020, $3.07 in 2030, and $3.66/Dth in 2040.

Q. HOW DID YOU ESTIMATE THE HEALTH COSTS OF NOX AND SO_2 EMISSIONS FROM POWER PLANTS?

A. As described in Appendix 6.1 of Exhibit TML-4, I used the EPA's estimates of the health-related damages of particulate matter resulting from releases of SO_2 and NOx by electric generators in a wide area encompassing the Philadelphia and New York City, which would be broadly typical of the area in which most of the electricity generated for PECo customers would be generated. Depending on the year, these estimates are around $100,000/ton for SO_2 and $1,500–$2,500/ton for NOx.

Appendix 6.1 of Exhibit TML-4 explains in some detail the manner in which I estimated the marginal emissions rates for PJM over time and converted the cost per ton to cost per MWh.

(D) Avoided Electric Costs

Q. WHY ARE AVOIDED ELECTRIC COSTS RELEVANT TO THE EVALUATION OF PGW'S ENERGY-EFFICIENCY PROGRAMS?

A. Gas energy-efficiency measures can increase or decrease electricity use. For example, tradeoffs between gas and electric savings arise in choosing between window designs that admit solar energy in the winter and those that keep out sunshine in the summer. On the other hand, building-shell measures (wall and roof insulation, tighter windows), setback thermostats, and duct sealing in gas-heated buildings are likely to decrease electric use both for circulating heat (with pumps and/or fans) and for summer cooling. Accurately evaluating the cost-effectiveness of the gas energy-efficiency and conservation programs requires valuation of the changes in electricity use, along with all other costs and benefits.

Q. HOW DID YOU ESTIMATE ELECTRIC AVOIDED COSTS?

A. My computation of avoided energy costs started with April 17 2014 NYMEX monthly forward on- and off-peak energy prices for PECo for 2015, escalated through 2018 at the growth rates for PJM energy.[10] After 2018, I interpolated the energy prices so that the growth rates matched the 2014 AEO's projection of nominal Henry Hub gas prices by 2026, and used AEO's escalation projections thereafter.[11] I then weighted the market energy costs across months, to derive an average annual avoided energy cost for each gas year.

I did not explicitly recognize any effects of intra-month load shape, line losses, carbon caps or changing fuel mix in the future.

To the energy costs, I added capacity costs at the market-clearing price applicable to electric service. Since PJM obtains capacity on a locational basis, the capacity price may be essentially uniform across the entire PJM RTO, or may vary between regions. The capacity price applicable to the Philadelphia region for 2014/15 through 2016/17 was the MAAC zone, plus losses and required reserves. I assumed that the capacity price after

---

[10] The forwards ran only to 2015 for PECo and 2018 for PJM

[11] This approach is very similar to that described by the PAPUC in Docket No. M 2009-2108601.

2016/17 would be constant in real terms, at the average of those three previous auction prices, which was about $73/kW-year including losses and reserves.

I also included the avoided T&D costs estimated by PECo in its Revised Phase II Energy Efficiency and Conservation Plan for Program Years 2013-2015 under Act 129. While these are avoided capacity costs, PECo reported them in dollars per kWh, and I included them as energy benefits.

The results of my computations are described in Exhibit PLC-3.

III. CONSERVATION ADJUSTMENT MECHANISM

Q. WHAT ISSUES WILL YOU ADDRESS REGARDING THE CONSERVATION ADJUSTMENT MECHANISM?

A. I will address the equity and efficiency benefits of inclusion of PGW's lost revenues in the Conservation Adjustment Mechanism (CAM).

Q. ARE LOST REVENUES A COST OF THE DSM PROGRAM TO PGW?

A. Yes. The principal purpose of energy-efficiency programs is to reduce customer costs by reducing the usage of commodity. The Total Resource Cost test (TRC), the primary test of efficiency-program effectiveness utilized by Act 129 programs in Pennsylvania and PGW's DSM, is based on the value to customers of the reductions in energy and capacity costs resulting from commodity savings. The benefits of efficiency programs exclude any additional short-term reductions in customer bills resulting from decreased contributions to paying for fixed utility costs. The short-term reduction in distribution charges is thus an unintended side-effect of the efficiency programming and is not counted as contributing towards PGW's stated goals or estimated benefits. Lost margins represent important additional costs imposed upon the utility and must be mitigated to facilitate full development of the efficiency resource. Since PGW flows through the costs of commodity to customers, reduced commodity use has little effect on PGW's financial condition, other than indirectly through the effect on cash working capital.

But in addition to commodity, PGW charges for distribution costs as a function of consumption, at about 60¢/Ccf for residential GS, and about 49¢/Ccf for PHA on GS, 47¢/Ccf for MS, 46¢/Ccf for commercial and municipal customers on GS and 45¢/Ccf for industrial customers. Since distribution costs are almost all fixed in the short term, every ccf of gas that a customer does not use due to an energy-efficiency or conservation program reduces PGW's earnings and cash flow. The better PGW does at reducing its customers' energy usage and bills, the worse off PGW would be under current ratemaking. These reductions in distribution charges to participating customers are not counted as benefits in measuring efficiency-program cost-effectiveness; the revenue reduction is an additional cost of program delivery borne by the utility. This additional unrecovered burden remains one of the major barriers to more effective energy policy in the states that have not addressed it.

As long as lost margins are not recovered, the scope of PGW's energy-efficiency programs must be limited to a level of effort that does not excessively burden PGW's financial structure and cash flow. Promoting all cost-effective energy-efficiency savings without recovery of lost margins could result in financial distress for PGW.

For lack of a mechanism for recovering lost margins, PGW was unable to propose growing its energy-efficiency programs to the expanded program level described in the DSM Phase II Plan. As a result, customers will pay more than necessary and more carbon pollution will be released to the atmosphere if the CAM is not approved.

Q. DOES LOST MARGIN REPRESENT A COST THAT SHOULD BE RECOGNIZED BY THE COMMISSION?

A. Yes. Lost margins constitute costs to PGW, which should be reflected in ratemaking to minimize the burden on PGW from aiding its customers.

Q. DO PGW'S LOST MARGINS INCLUDE ANY RETURN ON EQUITY?

A. No. I understand that PGW is a cash-flow regulated company, unlike investor-owned utilities whose rates include a component for return on rate base. Thus, PGW's margin only includes non-gas expenses, the costs of external borrowing, and an allowance to provide adequate cash flow as established in PGW's last base rate proceeding.

Q. ARE THE ELECTRIC UTILITIES AFFECTED BY LOST MARGINS TO THE SAME EXTENT AS PGW AND OTHER NATURAL GAS UTILITIES?

A. While the basic problem caused by lost margins is similar for electric and gas utilities, a few important factors tend to offset the severity of the burden for electric utilities. First, most electric utilities have continued to experience sales growth; the 2015 PJM load forecast shows the Pennsylvania electric utility sales growing at over 1% annually during the next three years, even after energy-efficiency programs. Thus, the lost contribution to fixed costs may be offset by increased contribution to fixed costs by increased sales. In contrast, like many gas utilities, PGW has been experiencing flat or negative sales growth and thus lacks that offset.[12] As explained by NARUC in 2007,

> While the gas industry generally faces declining average revenues per customer over time, the electric industry is experiencing increasing average revenues per customer. As a result, gas utilities tend to face revenue and profit erosion

---

[12] Some natural-gas companies have continued to experience load growth, due to expansion of their distribution system to new areas, construction of new homes, or increased demand for natural gas by commercial and industrial customers. None of these drivers of load growth is significant for PGW.

between rate cases, while electric utilities garner increasing revenue and profits between rate cases. [13]

Second, almost all electric utilities have demand-related infrastructure expansion projects planned over the relatively near term. When conservation reduces peak loads EDCs can mitigate the effect of those lost sales by deferring some demand-related costs between rate cases. PGW, like many gas utilities serving older urban areas, has little or no planned load-growth-related infrastructure investment to defer. PGW hence has no opportunity to reduce demand-related costs to offset lost contribution to fixed costs.

Finally, electric utilities have some categories of equipment that wear out faster when loaded more heavily in their safe operating range. In contrast, NGDCs have little (if any) equipment that wears out as a function of usage, so the lost contribution to fixed costs from energy-efficiency programs is not offset by reductions in load-related equipment failure.

Accordingly, while an appropriately structured mechanism for the recovery of lost margin due to conservation programs is justified for most utilities, such a mechanism is especially important for PGW.

Q. HOW DOES PGW PROPOSE TO RECOVER THE COSTS OF LOST MARGINS?

A. The company proposes to recover its lost margins resulting to sales reductions due to all its energy-efficiency programs. The recovery would be through the Conservation Adjustment Mechanism (CAM), an element of the existing DSM Efficiency Cost Recovery Mechanism (ECRM).

[13] "Decoupling For Electric & Gas Utilities: Frequently Asked Questions." National Association of Regulatory Utility Commissioners, September 2007, at 10.

Q. HOW WOULD THE LOST MARGINS BE ALLOCATED TO RATE CLASSES?

A. Each rate class would be allocated the lost margins resulting from energy-efficiency measures installed by the members of that class, except that the reduction in distribution bills of low-income customers covered by the Customer Responsibility Program (CRP) will be allocated among classes in the same manner that the CRP surcharge is allocated.

Q. DOES PGW EXPERIENCE LOST REVENUES FROM CUSTOMERS REDUCING THEIR USAGE AS A RESULT OF PARTICIPATION IN THE CRP HOME COMFORT PROGRAM?

A. Yes. While PGW recovers from other ratepayers the difference between a CRP customer's full bill (based on meter readings) and the customer's reduced payment responsibility (based on ability to pay), there is no mechanism that compensates PGW for lost margin when less gas flows through the CRP customer's meter due to energy-efficiency investments.

Q. PLEASE EXPLAIN THE COST RECOVERY OF REDUCED MARGINS RESULTING FROM ENERGY-EFFICIENCY EFFORTS AT THE HOMES OF THE LOW-INCOME CUSTOMERS COVERED BY THE CUSTOMER RESPONSIBILITY PROGRAM.

A. The lost margin from these customers would be included in the CAM. Customers participating in the CRP pay only a fixed dollar amount toward the bills associated with their usage. The remainder of their bills is paid by other customers through the Universal Service Surcharge; under current PGW practice, the lost margin is recovered from those same customers in a manner very similar to recovery of CRP costs. With a CAM in place the non-low-income customers will still benefit financially from CRP Home Comfort. The CRP surcharge would be reduced by the full reduction in gas costs in the bills of CRP customers, while the CAM mechanism would recover from the non-low income customers only the reduction in distribution charges. Thus, all the gas-related savings would be retained by the non-CRP customers, and the distribution charges related to fixed revenue requirements would flow through the CAM, offsetting the fixed-cost portion of the reduction in CRP recovery from non-CRP customers.

As discussed above, the lost margins from CRP Home Comfort are real costs to PGW: Revenues fall while PGW's fixed costs do not change. As a result, CRP Home Comfort increases the risk that PGW will not recover all of its fixed costs, ultimately impacting PGW's net operating margin. In order for PGW to go beyond the CRP Home Comfort minimum required under PUC regulation, a mechanism such as the CAM is necessary to ensure the recovery of these lost margins. The reduction in the reconciling charges (the OPEB, ECRM, Distribution System Improvement and Universal Service surcharges) is also not associated with any short-term savings, but the shortfall in PGW's recovery of these charges will be captured in future reconciliation (as it does currently) in the existing mechanisms and thus will not flow through the CAM.

In short, including the CRP Home Comfort lost margins in the CAM is good policy. Recovery of the CAM costs will allow PGW to expand its energy-efficiency program for CRP customers, ensure that the customers who subsidize CRP benefit from the gas cost savings resulting from CRP Home Comfort, and protect PGW from loss of margins needed to cover fixed costs.

Q. HOW WOULD LOST REVENUE BE DETERMINED?

A. The basic approach in computing lost revenues comprises the following steps, for each measure covered by an energy-efficiency and conservation program:

1) Count the number of measures installed under the program.

2) Estimate the annual sales effects of each measure.

3) Estimate the percentage of the savings that would have occurred without the program, and that therefore do not reflect any program-related revenue loss.

4) Estimate the extent of spillover from the program to non-participants, such as by increasing supply of efficient equipment available for purchase in the local market.

5) Determine the rate per ccf for the sales reduction, which may require, for example, tracking the number of participants in a boiler program who are on residential Rate GS, public-housing Rate GS, commercial Rate GS, Rate PHA, and Rate MS.

6) Compute when the savings from each measure would start, given both the installation schedule and the seasonality of load.

7) Compute the resulting lost revenues.

Q. WHAT FACTORS WOULD BE CONSIDERED IN ESTIMATING THE SALES EFFECTS OF EACH MEASURE?

A. The estimated effect on sales may depend on the following factors:

- the size of the equipment affected, such as the volume of the water heater or the Btu output rating of a furnace;
- building size;
- household size, especially for water heaters, and low-flow fixtures;
- pre-measure usage;
- efficiency of the rest of the system, such as the effect of the building envelope on the sales reduction from a more-efficient heating system.

Not all of these factors would be determined for each installation. Variables that would not be feasible to track for each installation would be determined from limited samples of participants.

Q. IS THIS APPROACH USED IN OTHER JURISDICTIONS?

A. Yes. Lost-revenue-adjustment mechanisms are used for electric and/or gas utilities in at least the following North American jurisdictions:

- Ontario,
- Arkansas,
- Arizona,
- Connecticut,
- Indiana,
- Kansas,
- Kentucky,
- Louisiana,
- Montana,
- Nevada,
- New Hampshire,
- North Carolina,
- Ohio,
- Oklahoma,
- Oregon,
- South Carolina, and
- Wyoming.

Lost-revenue adjustments have also been used in the past in several jurisdictions (such as Massachusetts, New Jersey, New York, and Maryland), but have been largely supplanted in those jurisdictions by revenue-stabilization or decoupling mechanisms that compare actual revenues to a target revenue level, and adjust rates to flow the difference to the utility or its customers.[14]

At least forty US jurisdictions (thirty-nine states and DC) have either lost-revenue adjustments or decoupling for electric and/or gas utilities.

Q. HAS PGW DEVELOPED DETAILED PROTOCOLS FOR THE TRACKING SYSTEM AND THE ESTIMATION OF LOST REVENUES?

A. Yes. Mr. Love includes a model tracking system and lost-revenue formulas in Appendix 6.2 of Exhibit TML-4.

Q. WOULD THE LOST-REVENUE COMPUTATION BE RESET AT SOME POINT?

A. Yes. In each rate proceeding, a new projection of pro-forma revenues is used to set rates. Accordingly, any lost-revenue amount in the ECRM would be eliminated at the effective date of the new rates.

Q. WOULD THE INCLUSION OF A PERFORMANCE-INCENTIVE MECHANISM OBVIATE THE NEED FOR RECOVERY OF LOST MARGINS?

A. No. The CAM would make PGW whole for the costs it has incurred for operation of the distribution system, but would lose due to the success of its energy-efficiency efforts. A reasonable assurance of not stressing the Company's finances is a minimum regulatory requirement for successful energy-efficiency implementation. The CAM recoveries would be needed to allow PGW to afford the pursuit of competent, cost-effective efforts.

---

[14] A revenue-stabilization mechanism would also allow PGW to pursue more cost-effective energy-efficiency savings.

Performance incentives, in contrast, reward and encourage the utility to pursue superior program designs and implementation approaches, to produce greater savings and greater benefits at lower costs. The CAM does not reward or encourage anything; it simply eliminates the financial damage associated with PGW's pursuit of benefits for its customers.

There is no fixed relationship between lost margins and performance incentives; neither of these ratemaking features substitutes for the other.

IV. CONCLUSION

Q. WHAT ARE YOUR CONCLUSIONS?

A. The avoided costs that I describe above and in my Exhibits are reasonable for cost-effectiveness screening of PGW's energy-efficiency and conservation programs.

The Commission should allow PGW to include recovery of lost margins from installed energy-efficiency measures, so that PGW can expand its energy-efficiency programs, reduce customer bills, moderate the risks of gas-price volatility, and reduce carbon emissions.

Q. DOES THIS COMPLETE YOUR DIRECT TESTIMONY?

A. Yes.

Exhibit PLC-1

Exhibit PLC-1

Paul L. Chernick

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

SUMMARY OF PROFESSIONAL EXPERIENCE

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

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

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

EDUCATION

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

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

HONORS

Chi Epsilon (Civil Engineering)

Tau Beta Pi (Engineering)

Sigma Xi (Research)

Institute Award, Institute of Public Utilities, 1981.

PUBLICATIONS

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

REPORTS

"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

"The Value of Demand Reduction Induced Price Effectsn" With Chris Neme. Web seminar sponsored by the Regulatory Assistance Project. March 18 2015.

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

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

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

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

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

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

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

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

"Cost-Effectiveness Analysis." Presentation as part of "Effective DSM Collaborative Processes," a week-long training session for Ohio DSM advocates sponsored by the Ohio Office of Energy Efficiency, August 1993.

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

"Using the Costs of Required Controls to Incorporate the Costs of Environmental Externalities in Non-Environmental Decision-Making." Presentation at the American Planning Association 1992 National Planning Conference; presentation cosponsored by the Edison Electric Institute. May 1992.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

ADVISORY ASSIGNMENTS TO REGULATORY COMMISSIONS

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

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

EXPERT TESTIMONY

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

85. **Ind. 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, 90-270; preliminary review of utility treatment of environmental externalities in October qualifying-facilities filings; Boston Gas Company. November 5 1990.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

103. **N.C. 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.); Coalition of Environmental Groups. October 1992.

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

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

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

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

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

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

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

108. **N.C. 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.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

128. **N.C. 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** FC917 II, prudence of DSM expenditures of Potomac Electric Power Company; Potomac Electric Power Company. Rebuttal testimony, February 1995.

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

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

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

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

Allocation of costs and benefits to rate classes.

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

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

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

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

135. **N.C. 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, Central Vermont Public Service Company rates; Vermont Department of Public Service. February 1996.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Performance incentives proposed for the Boston Edison company.

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

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

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

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

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

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

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

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

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

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 street lighting; Towns of Lexington and Acton. Affidavit, August 1998.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Review of proposed performance standards and valuation of performance.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Prudence of sale and management of auction. Benefits to ratepayers. Allocation and rate treatment of gain.

175. **Conn. DPUC** 99-09-12, Nuclear Divestiture by Connecticut Light & Power and United Illuminating; Connecticut Office of Consumer Counsel. January 2000.

Market for nuclear assets. Optimal structure of auctions. Value of minority rights. Timing of divestiture.

176. **Ont. Energy Board** RP-1999-0017, Union Gas PBR proposal; Green Energy Coalition. March 2000.

Lost-revenue-adjustment and shared-savings incentive mechanisms for Union Gas DSM programs. Standards for review of targets and achievements, computation of lost revenues. Need for DSM expenditure true-up mechanism.

177. **N.Y. PSC** 99-S-1621, Consolidated Edison steam rates; City of New York. April 2000.

Allocation of costs of former cogeneration plants, and of net proceeds of asset sale. Economic justification for steam-supply plans. Depreciation rates. Weather normalization and other rate adjustments.

178. **Maine PUC** 99-666, Central Maine Power alternative rate plan; Maine Public Advocate. Direct, May 2000; Surrebuttal, August 2000.

Likely merger savings. Savings and rate reductions from recent mergers. Implications for rates.

179. **Mass. EFSB** 97-4, Massachusetts Municipal Wholesale Electric Company gas-pipeline proposal; Town of Wilbraham, Mass. June 2000.

Economic justification for natural-gas pipeline. Role and jurisdiction of EFSB.

180. **Conn. DPUC** 99-09-03; Connecticut Natural Gas Corporation merger and rate plan; Connecticut office of Consumer Counsel. September 2000.

Performance-based ratemaking in light of mergers. Allocation of savings from merger. Earnings-sharing mechanism.

181. **Conn. DPUC** 99-09-12RE01, Proposed Millstone sale; Connecticut Office of Consumer Counsel. November 2000.

Requirements for review of auction of generation assets. Allocation of proceeds between units.

182. **Mass. DTE** 01-25, Purchase of streetlights from Commonwealth Electric; Cape Light Compact. January 2001

Municipal purchase of streetlights; Calculation of purchase price under state law; Determination of accumulated depreciation by asset.

183. **Conn. DPUC** 00-12-01 and 99-09-12RE03, Connecticut Light & Power rate design and standard offer; Connecticut Office of Consumer Counsel. March 2001.

Rate design and standard offer under restructuring law; Future rate impacts; Transition to restructured regime; Comparison of Connecticut and California restructuring challenges.

184. **Vt. PSB** 6460 & 6120, Central Vermont Public Service rates; Vermont Department of Public Service. Direct, March 2001; Surrebuttal, April 2001.

Review of decision in early 1990s to commit to long-term uneconomic purchase from Hydro Québec. Calculation of present damages from imprudence.

185. **N.J. BPU** EM00020106, Atlantic City Electric Company sale of fossil plants; New Jersey Ratepayer Advocate. Affidavit, May 2001.

Comparison of power-supply contracts. Comparison of plant costs to replacement power cost. Allocation of sales proceeds between subsidiaries.

186. **N.J. BPU** GM00080564, Public Service Electric and Gas transfer of gas supply contracts; New Jersey Ratepayer Advocate. Direct, May 2001.

Transfer of gas transportation contracts to unregulated affiliate. Potential for market power in wholesale gas supply and electric generation. Importance of reliable gas supply. Valuation of contracts. Effect of proposed requirements contract on rates. Regulation and design of standard-offer service.

187. **Conn.** DPUC 99-04-18 Phase 3, 99-09-03 Phase 2; Southern Connecticut Natural Gas and Connecticut Natural Gas rates and charges; Connecticut Office of Consumer Counsel. Direct, June 2001; supplemental, July 2001.

Identifying, quantifying, and allocating merger-related gas-supply savings between ratepayers and shareholders. Establishing baselines. Allocations between affiliates. Unaccounted-for gas.

188. **N.J. BPU** EX01050303, New Jersey electric companies' procurement of basic supply; New Jersey Ratepayer Advocate. August 2001.

Review of proposed statewide auction for purchase of power requirements. Market power. Risks to ratepayers of proposed auction.

189. **N.Y.** PSC 00-E-1208, Consolidated Edison rates; City of New York. October 2001.

Geographic allocation of stranded costs. Locational and postage-stamp rates. Causation of stranded costs. Relationship between market prices for power and stranded costs.

190. **Mass.** DTE 01-56, Berkshire Gas Company; Massachusetts Attorney General. October 2001.

Allocation of gas costs by load shape and season. Competition and cost allocation.

191. **N.J.** BPU EM00020106, Atlantic City Electric proposed sale of fossil plants; New Jersey Ratepayer Advocate. December 2001.

Current market value of generating plants vs. proposed purchase price.

192. **Vt.** PSB 6545, Vermont Yankee proposed sale; Vermont Department of Public Service. January 2002.

Comparison of sales price to other nuclear sales. Evaluation of auction design and implementation. Review of auction manager's valuation of bids.

193. **Conn. Siting Council** 217, Connecticut Light & Power proposed transmission line from Plumtree to Norwalk; Connecticut Office of Consumer Counsel. March 2002.

Nature of transmission problems. Potential for conservation and distributed resources to defer, reduce or avoid transmission investment. CL&P transmission planning process. Joint testimony with John Plunkett.

194. **Vt.** PSB 6596, Citizens Utilities rates; Vermont Department of Public Service. Direct, March 2002; rebuttal, May 2002.

Review of 1991 decision to commit to long-term uneconomic purchase from Hydro Québec. Alternatives; role of transmission constraints. Calculation of present damages from imprudence.

195. **Conn.** DPUC 01-10-10, United Illuminating rate plan; Connecticut Office of Consumer Counsel. April 2002

Allocation of excess earnings between shareholders and ratepayers. Asymmetry in treatment of over- and under-earning. Accelerated amortization of stranded costs. Effects of power-supply developments on ratepayer risks. Effect of proposed rate plan on utility risks and required return.

196. **Conn.** DPUC 01-12-13RE01, Seabrook proposed sale; Connecticut Office of Consumer Counsel. July 2002

Comparison of sales price to other nuclear sales. Evaluation of auction design and implementation. Assessment of valuation of purchased-power contracts.

197. **Ont. Energy Board** RP-2002-0120, review of transmission-system code; Green Energy Coalition. October 2002.

Cost allocation. Transmission charges. Societal cost-effectiveness. Environmental externalities.

198. **N.J.** BPU ER02080507, Jersey Central Power & Light rates; N.J. Division of the Ratepayer Advocate. Phase I December 2002; Phase II (oral) July 2003.

Prudence of procurement of electrical supply. Documentation of procurement decisions. Comparison of costs for subsidiaries with fixed versus flow-through cost recovery.

199. **Conn.** DPUC 03-07-02, CL&P rates; AARP. October 2003

Proposed distribution investments, including prudence of prior management of distribution system and utility's failure to make investments previously funded in rates. Cost controls. Application of rate cap. Legislative intent.

200. **Conn.** DPUC 03-07-01, CL&P transitional standard offer; AARP. November 2003.

Application of rate cap. Legislative intent.

201. **Vt.** PSB 6596, Vermont Electric Power Company and Green Mountain Power Northwest Reliability transmission plan; Conservation Law Foundation. December 2003.

Inadequacies of proposed transmission plan. Failure of to perform least-cost planning. Distributed resources.

202. **Ohio** PUC 03-2144-EL-ATA, Ohio Edison, Cleveland Electric, and Toledo Edison Cos. rates and transition charges; Green Mountain Energy Co. February 2004.

Pricing of standard-offer service in competitive markets. Critique of anticompetitive features of proposed standard-offer supply, including non-bypassable charges.

203. **N.Y.** PSC 03-G-1671 & 03-S-1672, Consolidated Edison company steam and gas rates; City of New York. Direct March 2004; rebuttal April 2004; settlement June 2004.

Prudence and cost allocation for the East River Repowering Project. Gas and steam energy conservation. Opportunities for cogeneration at existing steam plants.

204. **N.Y.** PSC 04-E-0572, Consolidated Edison rates and performance; City of New York. Direct, September 2004; rebuttal, October 2004.

Consolidated Edison's role in promoting adequate supply and demand resources. Integrated resource and T&D planning. Performance-based ratemaking and streetlighting.

205. **Ont. Energy Board** RP 2004-0188, cost recovery and DSM for Ontario electric-distribution utilities; Green Energy Coalition. Exhibit, December 2004.

Differences in ratemaking requirements for customer-side conservation and demand management versus utility-side efficiency improvements. Recovery of lost revenues or incentives. Reconciliation mechanism.

206. **Mass.** DTE 04-65, Cambridge Electric Light Co. streetlighting; City of Cambridge. Direct, October 2004; supplemental, January 2005.

Calculation of purchase price of street lights by the City of Cambridge.

207. **N.Y.** PSC 04-W-1221, rates, rules, charges, and regulations of United Water New Rochelle; Town of Eastchester and City of New Rochelle. Direct, February 2005.

Size and financing of proposed interconnection. Rate design. Water-mains replacement and related cost recovery. Lost and unaccounted-for water.

208. **N.Y.** PSC 05-M-0090, system-benefits charge; City of New York. Comments, March 2005.

Assessment and scope of, and potential for, New York system-benefits charges.

209. **Md.** PSC 9036, Baltimore Gas & Electric rates; Maryland Office of People's Counsel. Direct, August 2005.

Allocation of costs. Design of rates. Interruptible and firm rates.

210. **B.C. Utilities Commission** 3698388, British Columbia Hydro resource-acquisition plan; British Columbia Sustainable Energy Association and Sierra Club of Canada BC Chapter. September 2005.

Renewable energy and DSM. Economic tests of cost-effectiveness. Costs avoided by DSM.

211. **Conn.** DPUC 05-07-18, financial effect of long-term power contracts; Connecticut Office of Consumer Counsel. September 2005.

Assessment of effect of DSM, distributed generation, and capacity purchases on financial condition of utilities.

212. **Conn.** DPUC 03-07-01RE03 & 03-07-15RE02, incentives for power procurement; Connecticut Office of Consumer Counsel. Direct, September 2005; Additional, April 2006.

Utility obligations for generation procurement. Application of standards for utility incentives. Identification and quantification of effects of timing, load characteristics, and product definition.

213. **Conn.** DPUC Docket 05-10-03, Connecticut L&P; time-of-use, interruptible, and seasonal rates; Connecticut Office of Consumer Counsel. Direct and Supplemental Testimony February 2006.

Seasonal and time-of-use differentiation of generation, congestion, transmission and distribution costs; fixed and variable peak-period timing; identification of pricing seasons and seasonal peak periods; cost-effectiveness of time-of-use rates.

214. **Ont. Energy Board** Case EB-2005-0520, Union Gas rates; School Energy Coalition. Evidence, April 2006.

Rate design related to splitting commercial rate class into two classes. New break point, cost allocation, customer charges, commodity rate blocks.

215. **Ont. Energy Board** EB-2006-0021, Natural-gas demand-side-management generic issues proceeding; School Energy Coalition. Evidence, June 2006.

Multi-year planning and budgeting; lost-revenue adjustment mechanism; determining savings for incentives; oversight; program screening.

216. **Ind. Utility Regulatory Commission** 42943 and 43046, Vectren Energy DSM proceedings; Citizens Action Coalition. Direct, June 2006.

Rate decoupling and energy-efficiency goals.

217. **Penn.** PUC 00061346, Duquesne Lighting; Real-time pricing; PennFuture. Direct, July 2006; surrebuttal August 2006.

Real-time and time-dependent pricing; benefits of time-dependent pricing; appropriate metering technology; real-time rate design and customer information

218. **Penn.** PUC R-00061366 et al., rate-transition-plan proceedings of Metropolitan Edison and Pennsylvania Electric; Real-time pricing; PennFuture. Direct, July 2006; surrebuttal August 2006.

Real-time and time-dependent pricing; appropriate metering technology; real-time rate design and customer information.

219. **Conn.** DPUC 06-01-08, Connecticut L&P procurement of power for standard service and last-resort service; Connecticut Office of Consumer Counsel. Reports and technical hearings quarterly since September 2006.

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 05-1444-GA-UNC, recovery of conservation costs, decoupling, and rate-adjustment mechanisms for Vectren Energy Delivery of Ohio; Ohio Consumers' Counsel. February 2007.

Assessing cost-effectiveness of natural-gas energy-efficiency programs. Calculation of avoided costs. Impact on rates. System benefits of DSM.

224. **N.Y.** PSC 06-G-1332, Consolidated Edison Rates and Regulations; City of New York. March 2007.

Gas energy efficiency: benefits to customers, scope of cost-effective programs, revenue decoupling, shareholder incentives.

225. **Alb.** EUB 1500878, ATCo Electric rates; Association of Municipal Districts & Counties and Alberta Federation of Rural Electrical Associations. May 2007.

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

226. **Conn.** DPUC 07-04-24, review of capacity contracts under Energy Independence Act; Connecticut Office of Consumer Counsel. Direct (with Jonathan Wallach), June 2007.

Assessment of proposed capacity contracts for new combined-cycle, peakers and DSM. Evaluation of contracts for differences, modeling of energy, capacity and forward-reserve markets. Corrections of errors in computation of costs, valuation of energy-price effects of peakers, market-driven expansion plans and retirements, market response to contracted resource additions, DSM proposal evaluation.

227. **N.Y.** PSC 07-E-0524, Consolidated Edison electric rates; City of New York. September 2007.

Energy-efficiency planning. Recovery of DSM costs. Decoupling of rates from sales. Company incentives for DSM. Advanced metering. Resource planning.

228. **Man.** PUB 136-07, Manitoba Hydro rates; Resource Conservation Manitoba and Time to Respect Earth's Ecosystem. February 2008.

Revenue allocation, rate design, and demand-side management. Estimation of marginal costs and export revenues.

229. **Mass.** EFSB 07-7, DPU 07-58 & -59; proposed Brockton Power Company plant; Alliance Against Power Plant Location. March 2008

Regional supply and demand conditions. Effects of plant construction and operation on regional power supply and emissions.

230. **Conn.** DPUC 08-01-01, peaking generation projects; Connecticut Office of Consumer Counsel. Direct (with Jonathan Wallach), April 2008.

Assessment of proposed peaking projects. Valuation of peaking capacity. Modeling of energy margin, forward reserves, other project benefits.

231. **Ont. Energy Board** 2007-0905, Ontario Power Generation payments; Green Energy Coalition. April 2008.

Cost of capital for Hydro and nuclear investments. Financial risks of nuclear power.

232. **Utah** PSC 07-035-93, Rocky Mountain Power Rates; Utah Committee of Consumer Services. July 2008

Cost allocation and rate design. Cost of service. Correct classification of generation, transmission, and purchases.

233. **Ont. Energy Board** 2007-0707, Ontario Power Authority integrated system plan; Green Energy Coalition, Penimba Institute, and Ontario Sustainable Energy Association. Evidence (with Jonathan Wallach and Richard Mazzini), August 2008.

Critique of integrated system plan. Resource cost and characteristics; finance cost. Development of least-cost green-energy portfolio.

234. **N.Y.** PSC 08-E-0596, Consolidated Edison electric rates; City of New York. September 2008.

Estimated bills, automated meter reading, and advanced metering. Aggregation of building data. Targeted DSM program design. Using distributed generation to defer T&D investments.

235. **Conn.** DPUC 08-07-01, Integrated resource plan; Connecticut Office of Consumer Counsel. September 2008.

Integrated resource planning scope and purpose. Review of modeling and assumptions. Review of energy efficiency, peakers, demand response, nuclear, and renewables. Structuring of procurement contracts.

236. **Man.** PUB 2008 MH EIIR, Manitoba Hydro intensive industrial rates; Resource Conservation Manitoba and Time to Respect Earth's Ecosystem. November 2008.

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

237. **Md.** PSC 9036, Columbia Gas rates; Maryland Office of People's Counsel. January 2009.

Cost allocation and rate design. Critique of cost-of-service studies.

238. **Vt.** PSB 7440, extension of authority to operate Vermont Yankee; Conservation Law Foundation and Vermont Public Interest Research Group. Direct, February 2009; Surrebuttal, May 2009.

Adequacy of decommissioning funding. Potential benefits to Vermont of revenue-sharing provision. Risks to Vermont of underfunding decommissioning fund.

239. **N.S.** UARB 01439, Nova Scotia Power DSM and cost recovery; Nova Scotia Consumer Advocate. May 2009.

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

240. **N.S.** UARB 0496, proposed biomass project; Nova Scotia Consumer Advocate. June 2009.

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

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

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

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

Revenue-decoupling mechanism. Automatic rate adjustments.

243. Utah PSC 09-035-23, Rocky Mountain Power rates; Utah Office of Consumer Services. Direct, October 2009; rebuttal, November 2009.

Cost-of-service study. Cost allocators for generation, transmission, and substation.

244. Utah PSC 09-035-15, Rocky Mountain Power energy-cost-adjustment mechanism; Utah Office of Consumer Services. Direct, November 2009; surrebuttal, January 2010.

Automatic cost-adjustment mechanisms. Net power costs and related risks. Effects of energy-cost-adjustment mechanisms on utility performance.

245. Penn. PUC R-2009-2139884, Philadelphia Gas Works energy efficiency and cost recovery; Philadelphia Gas Works. December 2009.

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

246. B.C. Utilities Commission 3698573, British Columbia Hydro rates; British Columbia Sustainable Energy Association and Sierra Club British Columbia. February 2010.

Rate design and energy efficiency.

247. Ark. PSC 09-084-U, Entergy Arkansas rates; National Audubon Society and Audubon Arkansas. Direct, February 2010; surrebuttal, April 2010.

Recovery of revenues lost to efficiency programs. Determination of lost revenues. Incentive and recovery mechanisms.

248. Ark. PSC 10-010-U, Energy efficiency; National Audubon Society and Audubon Arkansas. Direct, March 2010; reply, April 2010.

Regulatory framework for utility energy-efficiency programs. Fuel-switching programs. Program administration, oversight, and coordination. Rationale for commercial and industrial efficiency programs. Benefit of energy efficiency.

249. Ark. PSC 08-137-U, Generic rate-making; National Audubon Society and Audubon Arkansas. Direct, March 2010; supplemental, October 2010; reply, October 2010.

Calculation of avoided costs. Recovery of utility energy-efficiency-program costs and lost revenues. Shareholder incentives for efficiency-program performance.

250. Plymouth, Mass., Superior Court Civil Action No. PLCV2006-00651-B (Hingham Municipal Lighting Plant v. Gas Recovery Systems LLC et al.), Breach of agreement; defendants. Affidavit, May 2010.

Contract interpretation. Meaning of capacity measures. Standard practices in capacity agreements. Power-pool rules and practices. Power planning and procurement.

251. N.S. UARB 02961, Port Hawkesbury biomass project; Nova Scotia Consumer Advocate. June 2010.

Least-cost planning and renewable-energy requirements. Feasibility versus alternatives. Unknown or poorly estimated costs.

252. **Mass.** DPU 10-54, NGrid purchase of long-term power from Cape Wind; Natural Resources Defense Council et al. July 2010.

Effects of renewable-energy projects on gas and electric market prices. Impacts on system reliability and peak loads. Importance of PPAs to renewable development. Effectiveness of proposed contracts as price edges.

253. **Md.** PSC 9230, Baltimore Gas & Electric rates; Maryland Office of People's Counsel. Direct, July 2010; rebuttal, surrebuttal, August 2010.

Allocation of gas- and electric-distribution costs. Critique of minimum-system analyses and direct assignment of shared plant. Allocation of environmental compliance costs. Allocation of revenue increases among rate classes.

254. **Ont. Energy Board** 2010-0008, Ontario Power Generation facilities charges; Green Energy Coalition. Evidence, August 2010.

Critique of including a return on CWIP in current rates. Setting cost of capital by business segment.

255. **N.S.** UARB Matter No. 03454, Heritage Gas rates; Nova Scotia Consumer Advocate. October 2010.

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

256. **Man.** PUB 17/10, Manitoba Hydro rates; Resource Conservation Manitoba and Time to Respect Earth's Ecosystem. December 2010.

Revenue-allocation and rate design. DSM program.

257. **N.S.** UARB 03665, Nova Scotia Power depreciation rates; Nova Scotia Consumer Advocate. February 2011.

Depreciation and rates.

258. **New Orleans City Council** UD-08-02, Entergy IRP rules; Alliance for Affordable Energy. December 2010.

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

259. **N.S.** UARB NSPI-P-892, depreciation Rates of Nova Scotia Power; Nova Scotia Consumer Advocate. February 2011.

Steam-plant retirement dates, post-retirement use, timing of decommissioning and removal costs.

260. **N.S.** UARB 03632, renewable-energy community-based feed-in tariffs; Nova Scotia Consumer Advocate. March 2011.

Adjustments to estimate of cost-based feed-in tariffs. Rate effects of feed-in tariffs.

261. **Mass.** EFSB 10-2/DPU 10-131, 10-132; NStar transmission; Town of Sandwich, Mass. Direct, May 2011; Surrebuttal, June 2011.

Need for new transmission; errors in load forecasting; probability of power outages.

262. **Utah** PSC 10-035-124, Rocky Mountain Power rate case; Utah Office of Consumer Services. June 2011.

Load data, allocation of generation plants, scrubbers, power purchases, and service drops. Marginal cost study: inclusion of all load-related transmission projects, critique of minimum- and zero-intercept methods for distribution. Residential rate design.

263. **N.S.** UARB 04104; Nova Scotia Power general rate application; Nova Scotia Consumer Advocate. August 2011.

Cost allocation: allocation of costs of wind power and substations. Rate design: marginal-cost-based rates, demand charges, time-of-use rates.

264. **N.S.** UARB 04175, Load-retention tariff; Nova Scotia Consumer Advocate. August 2011.

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

265. **Ark.** PSC 10-101-R, Rulemaking re self-directed energy efficiency for large customers; National Audubon Society and Audubon Arkansas. July 2011.

Structuring energy-efficiency programs for large customers.

266. **Okla. Corporation Commission** PUD 201100077, current and pending federal regulations and legislation affecting Oklahoma utilities; Sierra Club. Comments July, October 2011; presentation July 2011.

Challenges facing Oklahoma coal plants; efficiency, renewable and conventional resources available to replace existing coal plants; integrated environmental compliance planning.

267. **Nevada** PUC 11-08019, integrated analysis of resource acquisition, Sierra Club. Comments, September 2011; hearing, October 2011.

Scoping of integrated review of cost-effectiveness of continued operation of Reid Gardner 1–3 coal units.

268. **La.** PSC R-30021, Louisiana integrated-resource-planning rules; Alliance for Affordable Energy. Comments, October 2011.

Scoping of integrated review of cost-effectiveness of continued operation of Reid Gardner 1–3 coal units.

269. **Okla. Corporation Commission** PUD 201100087, Oklahoma Gas and Electric Company electric rates; Sierra Club. November 2011.

Resource monitoring and acquisition. Benefits to ratepayers of energy conservation and renewables. Supply planning

270. **Ky.** PSC 2011-00375, Kentucky utilities' purchase and construction of power plants; Sierra Club and National Resources Defense Council. December 2011.

Assessment of resources, especially renewables. Treatment of risk. Treatment of future environmental costs.

271. **N.S. UARB** 04819, demand-side-management plan of Efficiency Nova Scotia; Nova Scotia Consumer Advocate. May 2012.

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

272. **Kansas Corporation Commission** 12-GIMX-337-GIV, utility energy-efficiency programs; The Climate and Energy Project. June 2012.

Cost-benefit tests for energy-efficiency programs. Collaborative program design.

273. **N.S. UARB** 04862, Port Hawksbury load-retention mechanism; Nova Scotia Consumer Advocate. June 2012.

Effect on ratepayers of proposed load-retention tariff. Incremental capital costs, renewable-energy costs, and costs of operating biomass cogeneration plant.

274. **Utah PSC** 11-035-200, Rocky Mountain Power Rates; Utah Office of Consumer Council. June 2012.

Cost allocation. Estimation of marginal customer costs.

275. **Ark. PSC** 12-008-U, environmental controls at Southwestern Electric Power Company's Flint Creek plant; Sierra Club. Direct, June 2012; rebuttal, August 2012; further, March 2013.

Costs and benefits of environmental retrofit to permit continued operation of coal plant, versus other options including purchased gas generation, efficiency, and wind. Fuel-price projections. Need for transmission upgrades.

276. **U.S. EPA** EPA-R09-OAR-2012-0021, air-quality implementation plan; Sierra Club. September 2012.

Costs, financing, and rate effects of Apache coal-plant scrubbers. Relative incomes in service territories of Arizona Coop and other utilities.

277. **Arkansas** PSC Docket No. 07-016-U; Entergy Arkansas' integrated resource plan; Audubon Arkansas. Comments, September 2012.

Estimation of future gas prices. Estimation of energy-efficiency potential. Screening of resource decisions. Wind costs.

278. **Vt. PSB** 7862, Entergy Nuclear Vermont and Entergy Nuclear Operations petition to operate Vermont Yankee; Conservation Law Foundation. October 2012.

Effect of continued operation on market prices. Value of revenue-sharing agreement. Risks of underfunding decommissioning fund.

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

Estimation of marginal costs. Fuel switching.

280. **N.S. UARB** M05339, Capital Plan of Nova Scotia Power; Nova Scotia Consumer Advocate. January 2013.

Economic and financial modeling of investment. Treatment of AFUDC.

281. **N.S. UARB** M05416, South Canoe wind project of Nova Scotia Power; Nova Scotia Consumer Advocate. January 2013.

Revenue requirements. Allocation of tax benefits. Ratemaking.

282. **N.S. UARB** 05419; Maritime Link transmission project and related contracts, Nova Scotia Consumer Advocate and Small Business Advocate. Direct, April 2013; supplemental (with Seth Parker), November 2013.

Load forecast, including treatment of economy energy sales. Wind power cost forecasts. Cost effectiveness and risk of proposed project. Opportunities for improving economics of project.

283. **Ont. Energy Board** 2012-0451/0433/0074, Enbridge Gas Greater Toronto Area project; Green Energy Coalition. June 2013, revised August 2013.

Estimating gas pipeline and distribution costs avoidable through gas DSM and curtailment of electric generation. Integrating DSM and pipeline planning.

284. **N.S. UARB** 05092, tidal-energy feed-in-tariff rate; Nova Scotia Consumer Advocate. August 2013.

Purchase rate for test and demonstration projects. Maximizing benefits under rate-impact caps. Pricing to maximize provincial advantage as a hub for emerging tidal-power industry.

285. **N.S. UARB** 05473, Nova Scotia Power 2013 cost-of-service study; Nova Scotia Consumer Advocate. October 2013.

Cost-allocation and rate design.

286. **B.C. Utilities Commission** 3698715 & 3698719; performance-based ratemaking plan for FortisBC companies; British Columbia Sustainable Energy Association and Sierra Club British Columbia. Direct (with John Plunkett), December 2013.

Rationale for enhanced gas and electric DSM portfolios. Correction of utility estimates of electric avoided costs. Errors in program screening. Program potential. Recommended program ramp-up rates.

287. **Man.** PUB 2014, need for and alternatives to proposed hydro-electric facilities; Green Action Centre. Evidence (with Wesley Stevens) February 2014.

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

288. **Utah** PSC 13-035-184, Rocky Mountain Power Rates; Utah Office of Consumer Services. May 2014.

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

289. **Minn.** PSC E002/GR-13-868, Northern States Power rates; Clean Energy Intervenors. Direct, June 2014; rebuttal, July 2014; surrebuttal, August 2014.

Inclining-block residential rate design. Rationale for minimizing customer charges.

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

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

291. **Md.** PSC 9361, proposed merger of PEPCo Holdings into Exelon; Sierra Club and Chesapeake Climate Action Network. Direct, December 2014; surrebuttal, January 2015.

Effect of proposed merger on Consumer bills, renewable energy, energy efficiency, and climate goals.

292. **N.S.** UARB M06514, 2015 capital-expenditure plan of Nova Scotia Power; Nova Scotia Consumer Advocate. January 2015.

Economic evaluation of proposed projects. Treatment of AFUDC, overheads, and replacement costs of lost generation. Computation of rate effects of spending plan.

293. **Md.** PSC 9153 et al., Maryland energy-efficiency programs; Maryland Office of People's Counsel. January 2015.

Costs avoided by demand-side management. Demand-reduction-induced price effects.

294. **Québec** Régie de L'énergie R-3876-2013 phase 1, Gaz Métro cost allocation and rate structure; Regroupement des organismes environnementaux en énergie and Union des consommateurs. February 2015

Classification of the area-spanning system; minimum system and more realistic approaches. Allocation of overhead, energy-efficiency, gas-supply, engineering-and-planning, and billing costs.

ACRONYMS AND INITIALISMS

APS	Alleghany Power
ASLB	Atomic Safety and Licensing Board
BEP	Board of Environmental Protection
BPU	Board of Public Utilities
BRC	Board of Regulatory Commissioners
CMP	Central Maine Power
DER	Department of Environmental Regulation
DPS	Department of Public Service
DQE	Duquesne Light
DPUC	Department of Public Utilities Control
DSM	Demand-Side Management
DTE	Department of Telecommunications and Energy
EAB	Environmental Assessment Board
EFSB	Energy Facilities Siting Board
EFSC	Energy Facilities Siting Council
EUB	Energy and Utilities Board
FERC	Federal Energy Regulatory Commission
ISO	Independent System Operator
LRAM	Lost-Revenue-Adjustment Mechanism
NARUC	National Association of Regulatory Utility Commissioners
NEPOOL	New England Power Pool
NRC	Nuclear Regulatory Commission
OCA	Office of Consumer Advocate
PSB	Public Service Board
PBR	Performance-based Regulation
PSC	Public Service Commission
PUC	Public Utility Commission
PUB	Public Utilities Board
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 4/7/2015

Exhibit PLC-2

PGW Avoided Costs

Paul Chernick
Resource Insight, Inc.
April 29, 2014

The economic evaluation of an energy-efficiency measure requires an estimate of the measure's benefits. The major benefit of gas energy-efficiency programs is the reduction of gas use and associated costs to customers. Those avoided costs may be passed on to customers by the utility, third-party suppliers, or both, but they are all eventually paid by customers.

Electric avoided costs are often computed for a number of cost drivers, such as summer and winter contribution to system peak load, and seasonal energy use for on- and off-peak periods. In the cost-benefit computation, analysts estimate the effect of a proposed measure or program on each of the cost drivers. The benefit of the energy-efficiency proposal is then estimated by multiplying the energy savings for each cost driver by the per-unit avoided cost for that driver, and adding up the benefits for all the drivers. This approach works well for evaluation of electric energy-efficiency programs, simplifying the costs of serving loads for 8,760 hours to a few cost drivers, which can be estimated for the wide variety of electric end uses (*e.g.*, residential and commercial space heating, space cooling, ventilation, water heating, refrigeration, indoor and outdoor lighting, clothes drying, cooking, computers and other plug loads, as well as a range of industrial loads).

Like most detailed analyses of avoided gas costs, this study's calculation of avoided costs is structured differently than that usually used to estimate electric avoided costs. Planning and procurement for natural gas is primarily concerned with daily loads, rather than annual loads, so there are fewer load shapes. There are also fewer end uses for gas than electricity, since very little gas is used for lighting, refrigeration, or residential air conditioning, and no gas is used for computers or ventilation. Hence, it is feasible to compute avoided costs for the load shapes of the few gas end uses. In the cost-benefit analysis, the benefit of each energy-efficiency measure can be estimated as the measure's annual savings times a single load-specific avoided cost.

This load-shape approach to defining avoided costs allows for distinctions between the costs of different end uses that impose different costs, even for similar seasonal usage levels. An end use that does not vary with weather, such as cooking or clothes drying, may use the same amount of gas in the winter as a heating boiler, but the gas to serve the boiler will be more expensive. The boiler will predictably use more gas on very cold days, when gas is most expensive, and less on mild days, when gas is relatively cheap. Serving the boiler requires the reservation of enough pipeline capacity to meet load on typical cold days, and the construction of local transmission-and-distribution capacity and supplemental gas supplied to meet load on extraordinarily cold days. The boiler will use more gas on cold days, when regional gas demand is high and prices are high. The development of avoided cost by load shape allows for the reflection of these differences between loads even within a season or a month.

This estimate of avoided gas costs comprises the following four parts:

- Supply-area commodity costs: The price of futures contracts for delivery at Henry Hub, for normal-year weather.
- Commodity delivery costs: marginal pipeline and storage charges for gas delivered from Henry Hub to PGW's citygate in a normal year.
- Peaking capacity: The costs of local capacity to cover the difference between normal and design-peak conditions.
- Local transmission and distribution (T&D): The utility's cost of building, operating and maintaining the high-pressure transmission and lower-pressure distribution system in its service area

Supply-area Commodity Cost

We start with the forecast monthly gas price at Henry Hub for gas delivered evenly over the month for May 2014 through August December 2026, at the April 10, 2014 closing NYMEX forward price for gas delivered to Henry Hub. For gas year 2013/14, we used settlement data from the ICE exchange to calculate gas prices for September 2013 through January 2014 and NYMEX forwards from January 15, 2014 for the February through April 2014. To extend this forecast beyond 2024, we used the forecast of Henry Hub prices from the 2014 Annual Energy Outlook by the Energy Information Administration of the Department of Energy. Since the 2026 AEO forecast price was 25% higher than the average of the 2026 futures, we gradually phased the futures prices upward, by ⅛ of the price difference in 2019, 2/8 of the price difference in 2020, up to 8/8 in 2026. From 2027 through 2040, we inflate the AEO's Henry Hub gas price at a 2% escalation rate. Beyond 2040, we use the average AEO escalation rate for the last 14 years of the AEO forecast, about 4.6%.

Commodity Delivery Charges

For each month, we estimate the marginal delivery charge from the Texas Eastern tariff for deliveries from South Texas.[1] In the off-peak months of April through October, we assume that contract capacity is not a binding constraint and set the delivery charge at the difference between the variable commodity rate ($0.1105/Dth) and the basis differential between South Texas and Henry Hub (-$0.100).[2] In addition, the delivery costs include the 5.8% tariff transport fuel charge.

In the winter and shoulder months of November through March, we assume that marginal supply consists of 115 days of GSS storage and that demand contributes to the need for capacity. The 115 days of storage are distributed by percentage of annual heating degree days (HDD) with 25% of November days using storage, 68% of March days, and 100% of the days in December through February. Marginal supply requires transportation from South Texas to GSS, storage charges for capacity and demand, and transportation from GSS to city gate. Total fixed charges average $2.28 per Dth-Day over the 115 days

[1] The rates on Texas Eastern, adjusted for delivery basis to the pipeline, are all quite similar.

[2] Prices have historically been lower in South Texas than at Henry Hub.

($21.88/Dth-month). Allocating the fixed charges in proportion to normal heating load per storage day, we get fixed cost of storage ranging from $2.35 per Dth-Day in November climbing to $3.25 per Dth-Day in January and tapering down to $2.51 per Dth-Day in March. We add $0.51/Dth in commodity charges for transportation, injection and withdrawal, and 11.7% fuel charges for transportation and GSS.

Storage is the marginal resource December through February, but in November and March, the storage costs are blended with demand driven transportation costs. For days utilizing transportation only, we assume a fixed charge of transportation is $1.35 per Dth-Day ($17.06/Dth-month). Added to this is a variable commodity rate of $0.08/Dth and the 6.87% fuel charge. For November and March we calculate the monthly cost and fuel charge by averaging the transportation and storage costs by the number of days each service is used.

We assumed that these rates remain constant through the analysis period.

Load Shapes

From these forecast delivered prices, we computed annual delivered commodity costs for the following three load shapes:

- Baseload, including industrial processes, cooking, and clothes drying, modeled as using the same amount of gas every day.
- Space heating, modeled as using gas each day in proportion to daily heating degree days (HDD).
- Water heating, modeled as a mix of baseload and space-heating load. This approximation reflects the observation that gas usage by water-heating customers rises in the winter months, probably as a combination of higher standby losses and warmer water temperatures for baths, showers and washing.

Baseload Commodity

For baseload end uses, where use of gas does not vary with weather or the season, the analysis weights the forecast monthly gas price by the number of days in the month.

Space-Heating Commodity

The cost of commodity for space heating varies from the cost of baseload in two ways. First, the amount of gas used varies among months, and is concentrated in the higher-cost winter months. Second, within each month, space heating uses more gas on the colder days, when gas tends to be more expensive than the average for the month.

For the first factor, we assumed that the monthly use of gas for space heating is proportional to the monthly sum of daily heating degree days (HDDs). Heating degree days are the difference between the days' average temperature and a base temperature, at which space-heating use is assumed to be zero. That base temperature, or balance point, is lower than the temperature maintained by the thermostat, since the building is warmed by sun shining in the windows and by interior gains (waste heat) from lights, appliances, equipment, and people.

We used the monthly average HDDs with a base of 65° F for 1981-2010 published by NOAA.[3]

The second factor, the effect of the intra-month correlation of price and load, reflects the fact that heating loads use more gas on colder days within each month, and that prices tend to be higher on cold days.[4] This correction was computed as the typical ratio of the heating-load-weighted market price to the average daily price for the month. Since the NYMEX prices are for gas delivered evenly over the month, multiplying that ratio by the NYMEX-based price forecast results in an estimate of the price of gas for heating load in the month.

- Demand for gas for electric generation, which varies during the month with oil prices and outages of coal and nuclear plants and between years as load grows and supplies change.
- Gas production capacity, which changes within winter months primarily due to freeze-ups of gas wells in producing areas, but changes significantly between years due to depletion and new additions (and sometimes hurricanes).

For this study, the intra-month price ratio was computed for each calendar month using data for 2012 and 2013. The analysis computes the ratio of load-weighted to average monthly price for each month.

Equation 1: Intra-Month Heating Price Ratio.

$$\text{intra-month heating price ratio} = \frac{\left[\dfrac{\sum_{month} HD_{day} \times P_{day}}{\sum_{month} HD_{day}}\right]}{\left[\dfrac{\sum_{month} P_{day}}{\text{\# days in the month}}\right]}$$

where HD_{day} = heating degree-days for the day
P_{day} = delivered price for the day

The ratios tend to be highest in the winter and close to 1.00 in the shoulder months. The heating commodity cost for each year is the sum across months of the following product:

---

[3] Summary of Monthly Normals 1981-2010; Station: Philadelphia International Airport (KPHL); National Oceanographic and Atmospheric Administration, http://www.ncdc.noaa.gov/land-based-station-data/climate-normals/1981-2010-normals-data

[4] The utility or a gas supplier can meet load in those high-load high-priced days with spot purchases, by reserving storage and associated transportation to the citygate, or by reserving additional pipeline capacity directly to the citygate. All these approaches impose costs that would not be needed for a load that was constant across the days of the month.

NYMEX monthly forward × monthly HDD % × intra-month price ratio

The annual heating commodity cost is significantly greater than the annual baseload commodity cost. The annual residential heating avoided cost, averaged over the period 2006–2025, is 35% greater than average annual baseload price. These differences can largely be explained by the fact that most of the heating usage is in the high-priced months of January, February, and December.

Water-Heating Commodity

Based on previous experience, the analysis assumed that water-heating load is similar in shape to 75% baseload and 25% space-heating load. The heating-like shape is probably attributable to a combination of higher standby losses and longer, hotter showers and baths in cold weather.

Commodity-Cost Summary

The attached spreadsheet shows avoided commodity costs for the three load shapes. The relationships among the prices for the various load shapes are as expected. The heating cost is higher than the water-heating cost, which is higher than the baseload cost.

The average costs of utility gas supplies, which serve large amounts of heating load, tend to be much higher than the flat year-round gas supplies reflected in the baseload commodity costs. The average avoided commodity cost will similarly be more expensive than the avoided commodity cost for a flat year-round gas supply.

Peaking Capacity Cost

In addition to buying and delivering the gas required in a normal year, a gas utility must be prepared to meet much higher loads on an extremely cold (design-peak) day.[5] The prices for gas in a normal year do not include the costs of reserving capacity and supplies to meet design-day conditions. Those design loads are normally met by local storage (liquefied natural gas) and/or peaking off-system storage and associated transportation. We used a value of $80/year per Dth-day, based on the Texas Eastern SS-1B rate.

Since baseload has no increment of sendout on the design peak over average conditions, it would not have any peaking capacity charges.

While actual gas-system supply planning is quite complex, the problem was simplified by assuming that peaking capacity is required for the difference between sendout on a design peak day and on the average of the peak day in the two years. PGW's design day is 65 degree days, which was actually experienced on January 17, 1982. This design day level is 35 HDD higher than the average load in the winter months. Spread over 4,613 HDD in a normal year, peaking capacity requires backup of about 0.0075 Dth-day of capacity per Dth of usage, or about $0.70/Dth of heating load. We assume that the costs of peaking capacity rise at 2%, with inflation.

---

5 Energy supplies must also be sufficient to meet colder-than-normal weather for days or weeks at a time.

Exhibit PLC-3

Projection of PECo Avoided Costs Consistent with PGW Avoided-Cost Assumptions

Paul Chernick
Resource Insight, Inc.
April 29, 2014
(Updated April 2015)

In addition to gas, some PGW programs save electricity. Evaluation of those programs requires forecasts of the avoided cost of electricity in Philadelphia. We started with the values and approaches in "PECO Program Years 2013-2015 Act 129 – Revised Phase II Energy Efficiency and Conservation Plan" (January 24, 2013) and adjusted the values to be consistent with updated data and with the PGW avoided costs.

We used the same assumptions regarding gas price escalation and general inflation as in the PGW avoided costs.

Avoided Generation Energy

For avoided PECo energy costs, we used the PECo zone monthly day-ahead forwards (NYMEX products 4N and 4P), as of April 17, 2014, for the period through December 2015. For months for which no PECo price was reported, we interpolated between the months with reported prices, in proportion to the reported PJM Western Hub day-ahead forwards (NYMEX products J4 and E4). In each month, we computed the avoided energy cost for two periods (on- and off-peak, as defined by NYMEX).[1]

From January 2016 through 2018, we escalated the PECo monthly market prices by the growth in the PJM Western Hub day-ahead forwards, where available, or the PJM Western Hub real-time forwards (NYMEX products L1 and JP). From 2019 through 2025, we escalated the energy prices by the NYMEX Henry Hub gas prices (NYMEX product NG), plus the adders necessary to bring

[1] This on-peak period is broader than the on-peak period defined by PECo, but it is the version for which forward prices are available.

the NYMEX forwards up to the Henry Hub reference price forecast in the EIA's 2014 Annual Energy Outlook. From 2026 on, we use the Henry Hub escalation in the Annual Energy Outlook, corrected to a 2% general inflation rate.

This approach is very similar to that described by the PAPUC in Docket No. M 2009-2108601, which used the PJM Western Hub forwards for the first five years, Henry Hub for the next five years, and the AEO gas escalator thereafter. We used slightly more precise and relevant forwards that are now available, including the PECo forwards for about one year, the PJM western-hub forwards for three years, the Henry Hub forwards phasing into the AEO forecast for seven years, and the AEO forecast thereafter.

Avoided Generation Capacity

We started with the results for the MAAC zone (the price applicable for PECo customers) of PJM's last three base-residual auctions, for the following delivery years (June through May):

- 2014/15: $136.50/MW-day, or $49.82/kW-yr.
- 2015/16: $167.46/MW-day, or $61.12/kW-yr.
- 2016/17: $119.13/MW-day, or $43.48/kW-yr.

We estimated the cost for each calendar year as the weighted average of five months in the delivery year ending in the calendar year and seven months in the next calendar year. For computing the 2017 capacity price, we assumed that the 2017/18 price would be the average of the prices applicable to PECo for 2012/13 through as 2016/17 in real terms, or $62.78/kW-yr.[2] To these prices paid to resources, we added 22% to cover the required reserve margin, the extra reserves required by PJM whenever the market-clearing price is less than the ceiling price, and peak line losses.[3] We assumed that the price would remain at the 2017 level in real terms. Over 16,000 MW of new generic gas-fired combustion-turbine and

[2] The actual price for the MAAC zone in BRA 2017/18 was $120/MW-day or $41.40/kW-yr.

[3] The reserve requirements vary from year to year, depending on the results of PJM's reliability analysis and the market-clearing price, and PJM does not appear to publish estimates of line losses.

combined-cycle plants have cleared in the last three recent auctions, of which at least 12,000 MW cleared at less than $61/MW-day, including at least 6,000 MW in MAAC. These results suggest that our projected capacity prices are sufficient to bring new capacity on line as older coal plants retire.

The resulting values are shown in Table 1.

Table 1: Avoided Generation Capacity Costs (2014$)

Calendar Year	Capacity Cost ($/kW-yr)
2015	$67.89
2016	$56.70
2017 and after	$72.61

The institution of the PJM Capacity Performance is likely to increase prices starting with the 2016/17 delivery years. Our analysis was completed prior to PJM's Capacity Performance proposal, which is under consideration by FERC as of April 2015.

Avoided T&D

We took the avoided T&D costs in dollars per kWh from Table D-2 of PECo's Revised Phase II Act 129 Energy Efficiency and Conservation Plan for Program Years 2013-2015, PECo Exhibit No. 2. The avoided T&D costs are presented separately for residential, small C&I and large C&I. We weighted the avoided T&D costs 85% residential, 10% small C&I and 5% large C&I, roughly reflecting the mix of participants in PGW energy-efficiency programs.

The weighted avoided T&D costs are about $0.056/kWh.