BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

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

DIRECT TESTIMONY

of

Paul Chernick
Resource Insight, Inc.

On Behalf of
Philadelphia Gas Works

Topics Addressed:

Avoided Costs

DRIPE

October 23, 2020

TABLE OF CONTENTS

EXHIBITS

I. Introduction and Background

Q: Please identify yourself.

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

{J2703549.3}

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 three hundred and fifty times on utility issues before various regulatory, legislative, and judicial bodies, including utility regulators in 37 states and six Canadian provinces, and two Federal agencies.

Q: Have you testified previously before this Commission?

A: Yes. I have testified numerous times. Most relevant to the case at hand, I testified in :

- Docket No. R-2009-2139884, on the first five-year DSM plan of Philadelphia Gas Works; and
- This Docket No. P-2014-2459362, on the avoided costs and cost recovery for the 2016–2020 DSM plan of Philadelphia Gas Works. A complete list of my Pennsylvania testimony can be found in my resume, which is attached as Exhibit PLC-1.

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, 2013, 2018 and the current 2021 analysis.[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,
- Peoples Gas Company (Illinois) 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.

- PGW annually since 2009,
- Enbridge Gas in 2013,
- FortisBC in 2013,
- Enbridge and Union Gas in 2015,
- Peoples Gas in 2018,
- Various UGI divisions in 2015 through 2019.

Q: What is the purpose of your testimony?

A: The purpose of my testimony is to describe my derivation of PGW's avoided gas costs for the DSM III Implementation Plan described in the testimony of PGW witnesses Theodore Love and Denise Adamucci. 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 evaluating PGW's DSM III Energy-Efficiency Plan, as proposed by Mr. Love.

II. Overview of Avoided Costs

Q: Please describe the topics you will cover in this testimony.

A: I discuss the derivation of the forecast of commodity costs, of delivery costs, the end-use load shapes, and demand-reduction-induced price effect (DRIPE).

Q: What are avoided costs and how are they used in designing energy-efficiency programs?

A: The principal purpose of a utility energy-efficiency program is to reduce the cost of energy services for the utility's customers as a whole. To indicate whether the costs of the energy-efficiency program are justified by the benefits, we need an estimate of the costs avoided by load reductions.

Q: How are the avoided costs for gas utility energy-efficiency programs generally structured?

A: The costs avoided by reductions in natural-gas load consist of the price of gas in one or more production areas, the costs of delivering that gas to the utility's citygate, some reserve supply to serve load under extreme winter conditions, and the costs of expansion of delivery capacity on the utility's distribution system. The relevant period for those costs is the lifetime of measures planned or proposed for implementation. Since natural gas primarily serves just a few load types—mostly space heating, water heating and baseloads—most analyses estimate avoided costs for those load shapes, rather than by time periods (e.g., months, hours).

Q: Why does the process start with the price of gas in one or more production areas?

A: Since we need to project avoided costs for decades into the future, we need a forecast of the cost of commodity. Multi-year price trajectories are available for forward price contracts for natural gas at a number of locations, with the most active trading and the longest period of forward prices being those at the Henry Hub in Louisiana. Similarly, public forecasts of prices are available for Henry Hub from the U.S. Energy Information Administration.

Q: How are the avoided costs of delivering gas to the utility's citygate generally estimated?

A: The two general approaches are as follows:

1. Estimating the daily spot market price for natural gas at the utility's citygate, from the forecast and forward prices at Henry Hub (or some other supply point), plus the market-price differential from the supply point to the citygate. The market-price differential can be estimated from the historical difference (called "basis" in natural-gas supply jargon) between the supply and delivery points, or forward price quotes for that basis.
2. Estimating the costs of pipeline and storage contracts to transport and deliver firm gas to the utility. I use the second method, since it more directly reflects the costs of ensuring firm service to gas consumers.

Q: Did you include any avoided local distribution costs in PGW's avoided costs?

A: No.

III. Henry Hub Commodity Costs

Q: How did you derive your forecast of the price of commodity in the supply areas?

A: I used the Henry Hub price as the reference point for the forecast of commodity prices. I chose Henry Hub because, as I noted above, it is a highly liquid trading point, there is extensive historical and forward data on prices at Henry Hub and basis from Henry Hub to other points of interest, and the Annual Energy Outlook (AEO) of the Energy Information Administration provides a publicly-available Henry Hub price forecast.

Q: How did you forecast the Henry Hub price?

A: I used the Intercontinental Exchange (ICE) forwards through 2023, the AEO forecast from 2028 onwards, and a linear interpolation in 2024–2027.

Q: Did you make any adjustments in the ICE-derived Henry Hub price?

A: Yes, I adjusted the supply-area price downward to reflect the fact that PGW's supply contracts include transportation on the TETCO system from South Texas to the market zone. The forwards show the price of gas in South Texas to be less than the price at the Henry Hub, so I reduced by commodity cost by the basis from South Texas to Henry Hub, using the ICE forwards for the South-Texas basis through 2024. After 2024, I extrapolated the basis at half the annual change from 2023 to 2024.

IV. Load Shapes

Q: Why do you need to model end-use load shapes for natural gas?

A: The costs of gas service vary with the pattern of the gas consumption. An end use that uses about the same amount of gas every day or week, regardless of season or weather (e.g., clothes drying, cooking) can be served by pipeline supply contracts, with the costs spread over 365 days per year. A space-heating load, on the other hand, does not use any gas in much of the year, but uses substantial amounts in some months and very large amounts on exceptionally cold days. Serving space-heating load thus requires a mix of pipeline, storage (to use the gas brought in by the pipeline in the summer, and to have gas available on cold days when the pipelines are congested) and peaking resources for the coldest days in a normal year and the even colder days in an extreme design year.

Q: What load shapes did you model?

A: I developed avoided costs for three load shapes, to reflect the effect on PGW's load of the broad categories of DSM measures: baseload measures, which reduce load by the same amount each day of the year; space-heating measures, which reduce load in proportion to daily heating degree days (HDDs); and water-heating measures, which reduce load as some combination of the baseload and space-heating measures.

I estimated the commodity prices and transportation/storage costs separately for baseload and space-heating load, in some detail. I then estimated the avoided water-heating costs by weighting the final avoided costs for baseload and space heating.

Q: How did you convert the monthly prices to load shapes?

A: The baseload commodity price is the simple average of monthly prices. The space-heating commodity price is considerably more complicated.

A. *Space-Heating Load Shape*

Q: How did you model the space-heating load shape?

A: I assumed that space-heating load would be distributed across the months in proportion to monthly HDDs. In addition, the space-heating commodity price for each shoulder month (March–November) is adjusted by the ratio of HDD-weighted spot price to day-weighted spot price for the month.

Space-heating commodity price for December through February is computed from the prices for gas that would be put into storage evenly over the months of May to October. Prices for the space-heating load in the other months (of which only October, November, March, and April) start with the same monthly price as used for baseload commodity, but are adjusted up by one to six percent, to recognize the correlation of high-load and high-price days. The March space-heating commodity is modeled as the average of the storage commodity and the March HDD-weighted commodity.

Q: How did you estimate the adjustment for the correlation of high-load and high-price days?

A: The adjustment is based on historical ratio of the HDD-weighted daily price to the simple average of the daily prices in the month. Table 1 shows the monthly and annual results of this computation for the Transco non-NY Zone 6 (the delivery point used for spot prices in the Act 129 gas avoided-cost computation) in 2015 through 2020.

Table 1: Intramonthly Ratio of HDD-Weighted to Day-Weighted Price at Transco Zone 6 non-NY

	2015	2016	2017	2018	2019	2020
1	1.07	1.03	1.06	1.34	1.07	1.05
2	1.10	1.16	1.04	1.08	1.02	1.02
3	1.13	1.08	1.08	1.01	1.06	1.01
4	1.05	1.06	1.04	1.03	1.05	1.01
5	0.99	1.02	1.01	0.98	1.01	1.06
6	0.91	0.97	0.96	0.87	0.98	
7						
8						
9		0.59	0.64	0.90	1.15	0.82
10	1.00	1.13	1.07	1.09	1.06	
11	1.05	1.04	1.07	1.06	1.04	
12	1.09	1.04	1.22	1.03	1.04	
Average	1.059	1.069	1.074	1.078	1.044	
HDD-Weighted	1.075	1.068	1.085	1.109	1.048	

Q: How do you combine those prices into an avoided cost for space-heating load?

A: I weighted the monthly results described above by the monthly typical HDDs for space-heating load.

B. *Weighting of Water-Heating Load Shape*

Q: How did you estimate the avoided costs for water-heating?

A: I estimated water heating avoided costs as the weighted average of 75% baseload and 25% space-heating. I originally estimated that weighting in the late 1980s for the Boston Gas Company, based on monthly sales to customers with gas water-heating but no other uses.

Q: Why would water heating use vary with weather?

A: There are several factors that would increase gas use for water heating as temperatures and space-heating load rise. As a study by Bonneville Power Administration found:

> As indicated by the chart, there is a 20-25 % (88-108 kWh) decrease in energy consumption from winter to summer levels. Two seasonal effects could account for this drop: outside temperature and change in hot water demand. Water inlet temperature varies with outside temperature. During the colder winter months, more energy is required to heat water to the set point of the water heater if the outside water source is a lake or river.
>
> Decreased demand for hot water is another reason for seasonal variation in hot water energy use. Residential hot water demand is fundamentally affected by dish washing, clothes washing, and bathing, three uses that change from winter to summer.
>
> Warmer temperatures in the summer generally reduce the amount of indoor cooking….

> Summertime also means a decrease in the number of loads of laundry. People wear less clothes (shorts, sleeveless shirts) made of lightweight fabrics that don't take up much room in the washing machine. In contrast, in the colder winter, people wear more and heavier clothes that take up a lot of room in the washing machine and this results in more loads of laundry.
>
> Bathing habits also may change with seasons. It seems reasonable that cooler showers are taken in the warmer summer than are taken in the colder winter.
>
> Still another reason for decreased summer hot water loads is that summer is vacation season. When people are away from home, hot water isn't being used and the load can be expected to decrease to the standby load…[3]

In addition to the factors listed by Bonneville, lower ambient air temperatures will tend to increase standby losses from water heater and hot-water distribution pipes.

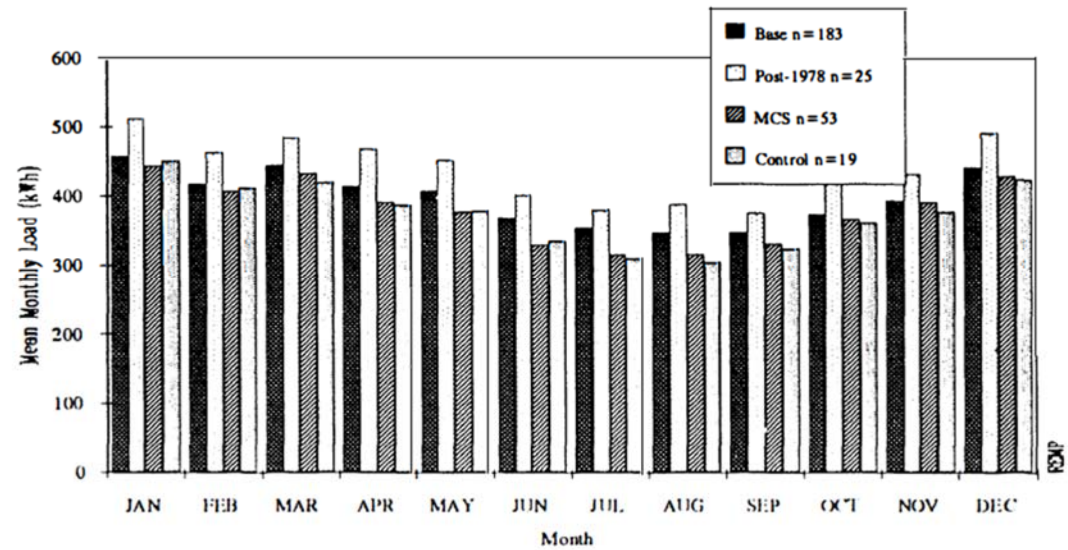
Q: Do analyses of water-heating load shape generally show higher usage as temperature falls?

A: Yes. This is demonstrated in Figure 1 and Figure 2, from studies in the Northwest and Florida, respectively.

---

[3] Hot Water Electric Energy Use in Single-Family Residences in the Pacific Northwest, Regional End-Use Metering Project, Bonneville Power Administration, September 1991, p. 7-11 to 7-12.

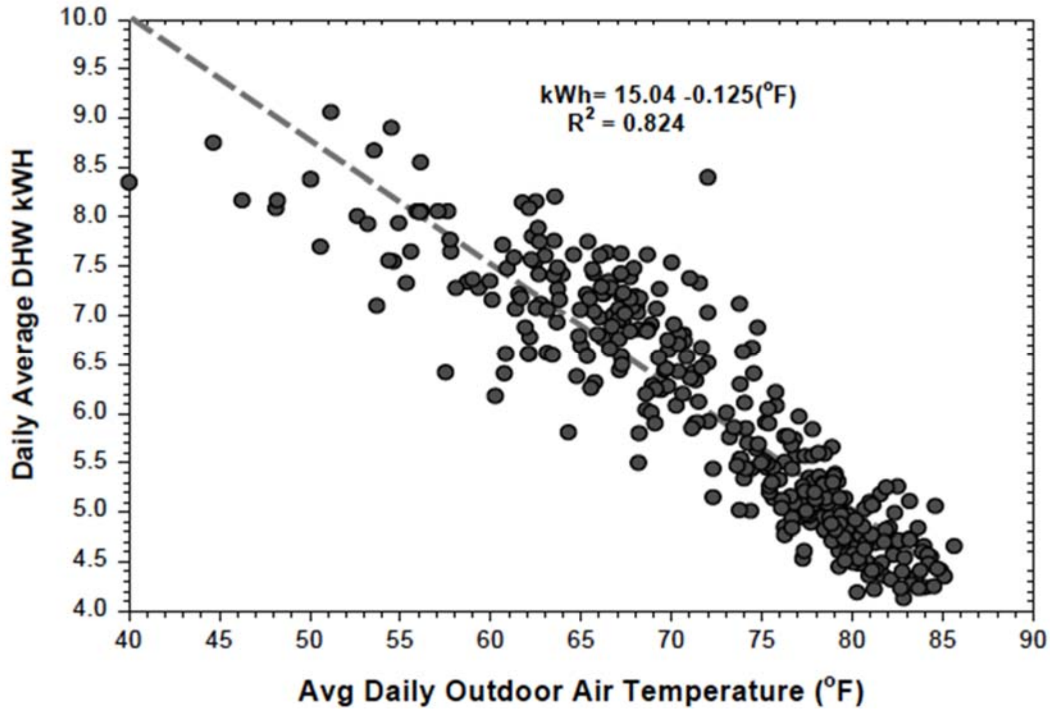
Figure 1: Mean Pacific Northwest Residential Hot Water Monthly Loads by Study, 1986-1990[4]



[4] Hot Water Electric Energy Use in Single-Family Residences in the Pacific Northwest, Regional End-Use Metering Project, Bonneville Power Administration, September 1991, Figure 7.6.

{J2703549.3}

Figure 2: Impact of Average Air Temperature on Daily Florida Average Water-heating Usage[5]



Q: Can you determine the weighting of baseload and space-heating load that would be consistent with any of these studies?

A: Yes.

- Using 2016 through 2019 daily climate data for Philadelphia, the regression equation from Figure 2 predicts that base load (which I defined as the average of predicted water heater load in July and August) would account for about 69% to 73% of predicted water-heating annual load.

---

[5] "Factors Influencing Water Heating Energy Use and Peak Demand in a Large Scale Residential Monitoring Study," Matthew P. Bouchelle, Danny S. Parker and Michael T. Anello, in Residential Buildings: Technologies, Design, Performance Analysis, and Building Industry Trends, ACEEE, pp. 1.157 to 1.170, Figure 5.

- The water-heating load shape estimated in the 2018 New England avoided-cost study estimated that base load accounts for only 22% of the annual water heating load.[6]
- The load shapes for water heating used by the Massachusetts energy-efficiency program administrators are about 75% baseload for residential electric water heating and 83% for gas water heating.[7]
- A study by Northwestern Energy (which serves parts of Montana and South Dakota) indicates that the baseload water-heater energy would account for about 82% to 87% of residential water-heater usage, depending on whether the water heating is fueled by electricity or gas, and on whether the home was single-family or multi-family.

These ratios would be expected to vary depending on climate, the building stock, household characteristics, appliance ownership (clothes washer and dishwasher), and other factors.

[6] "Avoided Energy Supply Costs in New England: 2018 Report" (Pat Knight, Max Chang, David White, Paul Chernick, Benjamin Griffiths, Les Deman, John Rosenkranz, Jason Gifford, and others). March 30, 2018. Cambridge, Mass.: Synapse Energy Economics., Table 11

[7] http://ma-eeac.org/wordpress/wp-content/uploads/Appendix-B-6-2-Water-Heating-Electric-Load-Shape-Results-2020-03-31.xlsx

V. Delivery Costs

Q: How did you estimate the transportation cost from the supply areas to the PGW citygate?

A: I examined PGW's filing in Docket R-2019-3007636 and identified what appear to be the marginal supplies for baseload pipeline supply, winter storage, and peaking supply. The supplies I identified were:

- For baseload, Texas Eastern Transmission Company (TETCO) Comprehensive Delivery Service (CDS) from South Texas to TETCo market zone M-3.
- For winter supply, Dominion GSS storage, plus FTS-7 TETCo Firm Transportation to GSS storage and FTS-8 TETCo Firm Transportation from GSS storage.
- For peaking supply, TETCo storage supplies SS-1A and SS-1B.

Q: What are the costs and characteristics of those supplies?

A: Table 2 summarizes those characteristics, including the demand charges, commodity charges, fuel use factor, the number of days in which I treat the supply as marginal, the assumed utilization factor for the supply in that period.

The demand prices in $/month per dekatherm-day (which I simplify to $/Dth-month) and commodity costs in $/Dth are from PGW's filing in Docket R-2019-3007636 and TETCo's tariff filing. In most cases, I convert the demand prices to $/Dth-year by multiplying by 12 and to $/Dth by dividing by days. The exceptions are the capacity or space charges, which pay for reservation of the storage volumes, and are converted to $/Dth-year by multiplying by 12 and by the number of days of gas being stored. Fuel use for the SS-1 storage resources is the charge per Dth/month for the inventory in storage; I multiply those by 6.5 months from the average time gas would be put into storage and the average time it would be withdrawn.

Table 2: Characteristics of Marginal Gas Supplies

	Days on margin	Demand $/Dth-month	Demand $/Dth-year	Demand $/Dth	Commodity $/Dth	Fuel Dec-Mar	Fuel Apr-Nov
Firm Transportation - CDS							
STX-AAB	250	$7.376	$88.5	$0.354			
MKT1-MKT3	250	$12.491	$149.9	$0.600			
Total	250	$19.867	$238.4	$0.954	**$0.103**	**4.03%**	**3.15%**
Assumed Usage	69%			**$1.382**			
Firm Storage Dominion GSS							
Demand	115	$1.870	$22.4	$0.195			
Capacity	115	$0.015	$20.0	$0.174			
Injection	115				$0.027		
Withdrawal	115				$0.014		
GSS-TE Surcharge	115				$0.005	1.95%	1.95%
South Texas to M-2						2.81%	2.81%
FTS-7 Firm Transport to GSS	115	$7.425	$89.1	$0.774			
FTS-8 Firm Transport from GSS	115	$7.281	$87.4	$0.759			
Total			$218.9	$1.902	**$0.046**	**4.76%**	4.76%
Assumed Usage	73%			**$2.606**			
Firm Storage SS-1A							
Demand (Reservation Charge)	10	$6.574	$78.9	$7.889			
Capacity (Space Charge)	10	$0.337	$40.5	$4.045		0.05%	0.05%
Injection	10				$0.046	1.73%	1.76%
Withdrawal	10				$0.071	0.63%	0.63%
FTS-2 Firm Transportation	10	$8.464	$101.6	$10.157			
FTS-7 M-2 to M-3						2.00%	2.00%
FTS-8 M-2 to M-3						1.50%	1.50%
Total	10		$220.9	$22.091	**$0.117**	**6.19%**	6.22%
Assumed Usage	80%			**$27.614**			
Firm Storage SS-1B							
Demand (Reservation Charge)	10	$6.574	$78.9	$7.889			
Capacity (Space Charge)	10	$0.337	$40.5	$4.045		0.05%	0.05%
Injection	10				$0.046	1.73%	1.76%
Withdrawal	10				$0.071	0.63%	0.63%
FTS-2 Firm Transportation	10	$8.464	$101.6	$10.157			
FTS-7 M-2 to M-3						2.00%	2.00%
FTS-8 M-2 to M-3						1.50%	1.50%
Total			$220.9	$22.091	**$0.117**	**6.19%**	6.22%
Assumed Usage	75%			**$29.454**			

The days on margin are based on the ratio of PGW's capacity reservation to the demand reservation for the GSS and SS-1B resources. For SS-1A, PGW has only 5 days of space reserved per Dth/day, but I used the

10-day value for SS-1B, to be conservative. The 250 days for CDS is the difference between the 365 days in the year and the 115 days covered by GSS.

Q: Do you include any other capacity resources?

A: Yes. The computations described above reflect only normal weather conditions. In addition, PGW must procure enough capacity to meet the design peak day. It is my understanding that the design peak day for Philadelphia is 65 HDDs, equivalent to an average temperature of 0°F. This is 12 HDD higher than the coldest day in 2015–2018. The cost of those 12 HDD, spread over an annual average of 4,745 HDD, requires that every unit of space-heating energy support 0.0025 units of reserve capacity.

I priced that reserve capacity at the fixed costs of the SS1-B storage resource. I did not include the cost of the gas commodity, since that gas will be useful for something, probably at the end of the heating season, once PGW can be confident that it will not face a design peak day. I also did not include the cost of supply to ride out a multi-day cold snap, such as the past Polar Vortex events.

Q: How did you assign these costs to months?

A: The transportation cost for the off-peak months is from the CDS tariff for shipping from South Texas to the M-3 market zone. The cost for December to March is based on the GSS storage rates for 115-day storage, with March prorated between GSS and CDS. The January storage cost is the weighted average of GSS (50%), the SS-1A (25%) and the SS-1B (25%) supply, to reflect PGW's use of those peaking resources. The high-cost days that require the use of the SS-1 supplies may be spread over the various winter months, but the annual cost for space-heating load would not change much with reallocation among months.

VI. Comparison to Act 129 Avoided Costs for Electric Energy-Efficiency Programs

Q: How does your approach to avoided natural-gas costs compare to that adopted by the Commission for the Act 129 energy-efficiency programs?

A: The PGW avoided costs use some of the same components as the simplified avoided costs for incidental natural gas reductions in the EDC programs, as described in the 2021 TRC Cost Final Order in M-2019-3006868. These include the use of NYMEX gas prices at Henry Hub in the short term, blending into the AEO forecast and the delivery of gas to the TETCo M-3 hub.

The most important differences between the PGW avoided costs and the Act 129 avoided costs for natural gas are:

- The delivery portion of Act 129 natural-gas avoided costs are based on forward market contract prices by month, for the basis from Henry Hub to Transco non-New York Zone 6, which includes delivery points in eastern Pennsylvania and in New Jersey. The PGW avoided costs use actual tariff prices for firm transportation to the TETCo Zone M-3. Both the forward basis and the tariff rates for

{J2703549.3}

delivery to Transco Zone 6 are higher than those for TETCo Zone 3, so the PGW avoided costs are lower than they would have been if they followed the TRC order in this regard.

- The Act 129 avoided gas costs do not reflect costs that the PGW avoided costs incorporate:
  - the shapes of space heating load within each month,
  - the cost of securing firm prices for secure delivery of gas to the citygate, or
  - the cost of reserve capacity to cover space-heating load for extreme weather.

Q: Is there any reason that the Act 129 avoided gas costs would be computed in a different manner than the avoided gas costs for a natural-gas utility's energy-efficiency program?

A: Yes. The Act 129 computation is easy to apply for the EDCs, which are not generally in the business of procuring retail gas supplies for their service territories. Some of the EDC territories overlap with multiple gas distribution utilities. Developing detailed contract-based avoided costs for even one gas company, let alone several, would be a significant effort, and reviewing those estimates would also require significant efforts. The Commission's decision to use a simpler approximation for the incidental gas savings from electric energy-efficiency programs was quite reasonable.

On the other hand, the avoided costs for the natural-gas utilities' own energy-efficiency programs can and should more realistically reflect the costs of their procurement practices.

Q: Has the Commission recognized this distinction?

A: Yes. The Commission was asked by OSBA to mandate a uniform methodology for natural gas avoided costs for both Act 129 programs by the electric utilities and energy-efficiency programs by the gas utilities. The Commission declined:

> We reject OSBA's recommendation to have the Phase III SWE develop a methodology for calculating the avoided, delivered natural gas costs for both winter season and year-round applications for use in both NGDC and EDC EE&C programs … [N]atural gas impacts are a secondary benefit for Act 129 electric programs, but the primary benefit for NGDC EE&C plans. It follows that the level of rigor and granularity used for avoided costs may be different. Similarly, we would accept certain simplifying assumptions in a NGDC's avoided cost of electricity forecast for measures that happen to also save electric energy that would not be acceptable in an electric EE&C plan. (Act 129 2021 TRC Cost Final Order in M-2019-3006868, p. 11)

I agree with the Commission's reasoning.

VII. Demand-Reduction Induce Price Effects

Q: What are Demand-Reduction Induce Price Effects?

A: Demand-Reduction Induce Price Effects (DRIPE) reflect the reduction in prices to customers (in the case of PGW, Pennsylvania customers) due to reduced energy consumption. In terms of natural gas, reduced consumption reduces the market-clearing price for natural gas at the supply zones, and also reduces the winter congestion on the pipelines for spot purchases and future contracts in the delivery areas. Since gas-fired electric generation depends primarily on spot gas purchases, reduced consumption of natural gas by Pennsylvania retail customers reduces electric prices in the PJM market. The value of DRIPE is included in the avoided costs used by Mr. Love in screening energy-efficiency programs.

Q: How did you estimate the DRIPE values?

A: Exhibit PLC-2 provides the derivation of the DRIPE values in 2015. The calculations were not updated for this analysis, but simply carried forward to later years.

VIII. Conclusion

Q: What do you recommend?

A: Based upon my experience with review and development of avoided natural gas costs, I recommend that the Commission accept the use of the PGW-specific avoided costs that I developed for this filing, including the DRIPE values.

Q: Does this conclude your testimony?

A: Yes.

VERIFICATION

I, Paul Chernick, hereby state that: (1) I am President of Resource Insight, Inc.; (2) I have been retained by Philadelphia Gas Works ("PGW") for purposes of this proceeding.; (3) the facts set forth in my testimony are true and correct to the best of my knowledge, information and belief; and (4) I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa.C .S. § 4904 (relating to unsworn falsification to authorities).

October 22, 2020	Paul Chernick
Dated	Paul Chernick President Resource Insight, Inc.

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

"Review of NS Power Compliance Filing on its Proposed AMI Opt-Out Charge" (with Benjamin Griffiths). October 26, 2018. Filed by the Nova Scotia Consumer Advocate in N.S. UARB Matter No. M08349.

"Avoided Energy Supply Costs in New England: 2018 Report" (with Pat Knight, Max Chang, David White, Benjamin Griffiths, Les Deman, John Rosenkranz, Jason Gifford, and others). March 30, 2018. Cambridge, Mass.: Synapse Energy Economics.

"Review of the NS Power Application for Approval of its 2017 Annually Adjusted Rates and Load Following Setting Methodology" (with Stacia Harper). August 2017. Filed by the Nova Scotia Consumer Advocate in N.S. UARB Matter No. M08114.

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

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

"Comments on Nova Scotia Power Inc.'s Proposed Capital Expenditure Justification Criteria." 2013. Filed by the Nova Scotia Consumer 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). 2013. 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: 2009 Report" (with Rick Hornby, Carl Swanson, David White, Ian Goodman, Bob Grace, Bruce Biewald, Ben Warfield, Jason Gifford, and Max Chang). 2009. Northborough, Mass.: Avoided-Energy-Supply-Component Study Group, c/o National Grid Company.

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

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

"Avoided Energy Supply Costs in New England: 2007 Final Report" (with Rick Hornby, Carl Swanson, Michael Drunsic, David White, Bruce Biewald, and Jenifer Callay). 2007.

Northborough, Mass.: Avoided-Energy-Supply-Component Study Group, c/o National Grid Company.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

PRESENTATIONS

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

"Least Cost Planning and Gas Utilities." Demand-Side Management and the Global Environment Conference; Washington, D.C. April 22 1991.

Conservation Law Foundation Utility Energy Efficiency Advocacy Workshop; Boston, February 28 1991.

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

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

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

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

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

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

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

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

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

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

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

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

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

ADVISORY ASSIGNMENTS TO REGULATORY COMMISSIONS

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

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

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

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

EXPERT TESTIMONY

1. **Mass. EFSC** 78-12/MDPU 19494, Phase I; Boston Edison 1978 forecast; Massachusetts Attorney General. June 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 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 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 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 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 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 1979.

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

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 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 1980.

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

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

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

13. **Texas PUC** 3298, Gulf States Utilities rates; East Texas Legal Services. August 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 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 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 1981 and February 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 1981.

    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 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. **DC PSC** FC785, Potomac Electric Power rate case; DC Peoples Counsel. July 1982.

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

21. **N.H. PSC** DE 81-312, Public Service of New Hampshire supply and demand; Conservation Law Foundation et al. October 1982.

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

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

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

23. **Ill. CC** 82-0026, Commonwealth Edison rate case; Illinois Attorney General. October 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 1983.

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

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

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

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

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

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

    Profit margin calculations, including methodology, interest rates.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

38. **N.H. PSC** 84-200, Seabrook Unit-1 investigation; New Hampshire Consumer Advocate. November 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 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 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 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 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 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 1985 and October 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 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 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 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 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 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 1986.

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

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

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 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 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 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 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 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 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 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 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 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 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 1988.

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

68. **Mass. DPU** 88-123, petition of Riverside Steam & Electric; Riverside Steam and Electric Company. May 1988 and November 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 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 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 1988, supplemented August 1988; Losses and Expenses, September 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 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 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 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 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 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 rates; Massachusetts Energy Office. June 1989.

Prudence of decision to spend $400 million from 1986–88 to return Pilgrim nuclear 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 1989. Rebuttal, October 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 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 1989. Surrebuttal February 1990.

    Analysis of a proposed 20-year power purchase. Comparison to efficiency investment. Critique of conservation potential analysis. Analysis of Vermont electric energy supply. Planning risk of large supply additions. Valuation of environmental externalities. Identification of possible improvements to proposed contract.

81. **Mass. DPU** 89-239, inclusion of externalities in energy-supply planning, acquisition, and dispatch for Massachusetts utilities. Boston Gas Company. 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 1990.

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

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

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

85. **Ind. URC,** integrated-resource-planning docket; Indiana Office of Utility Consumer Counselor. November 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 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 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 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, commission investigation; Southern Environmental Law Center. March 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 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 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 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 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 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 1991.

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

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

Obligation to pursue integrated resource planning, 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 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 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 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 1992.

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

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

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

108. **N.C. UC** E-100 Sub 64, analysis and investigation of least cost integrated resource planning in North Carolina; Southern Environmental Law Center. November 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 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 1993; rebuttal February 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 to Potomac Edison purchase agreement with AES Warrior Run; Maryland Office of People's Counsel. January 29 1993.

Economic analysis of proposed coal-fired cogeneration facility.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Allocation of costs and benefits to rate classes.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

LRAM and incentive mechanisms in rates for the Consumers Gas Company.

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

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

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

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

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

Performance incentives proposed for the Boston Edison company.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Review of proposed performance standards and valuation of performance.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Application of rate cap. Legislative intent.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Rate decoupling and energy-efficiency goals.

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

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

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

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

219. **Conn. DPUC** 06-01-08, Connecticut L&P procurement of power for standard service and last-resort service; Connecticut Office of Consumer Counsel. Reports and technical hearings quarterly since September 2006 to October 2013.

Conduct of auction; review of bids; comparison to market prices; selection of winning bidders.

220. **Conn. DPUC** 06-01-08, United Illuminating procurement of power for standard service and last-resort service; Connecticut Office of Consumer Counsel. Reports and technical hearings quarterly August 2006 to October 2013.

Conduct of auction; review of bids; comparison to market prices; selection of winning bidders.

221. **N.Y. PSC** 06-M-1017, policies, practices, and procedures for utility commodity supply service; City of New York. Comments, November and December 2006.

Multi-year contracts, long-term planning, new resources, procurement by utilities and other entities, cost recovery.

222. **Conn. DPUC** 06-01-08, procurement of power for standard service and last-resort service, lessons learned; Connecticut Office Of Consumer Counsel. Comments and Technical Conferences December 2006 and January 2007.

Sharing of data and sources; benchmark prices; need for predictability, transparency and adequate review; utility-owned resources; long-term firm contracts.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

239. **N.S. UARB** M01439, Nova Scotia Power DSM and cost recovery; Nova Scotia Consumer Advocate. May 2009.

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

240. **N.S. UARB** M01496, proposed biomass project; Nova Scotia Consumer Advocate. June 2009.

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

241. **Conn. Siting Council** 370A, Connecticut Light & Power transmission projects; Connecticut Office of Consumer Counsel. July 2009. Also filed and presented in **MA EFSB** 08-02, February 2010.

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

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

Revenue-decoupling mechanism. Automatic rate adjustments.

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

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

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

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

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

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

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

Rate design and energy efficiency.

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

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

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

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

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

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

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

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

251. **N.S. UARB** M02961, Port Hawkesbury biomass project; Nova Scotia Consumer Advocate. June 2010.

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

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

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

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

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

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

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

255. **N.S. UARB** 03454, Heritage Gas rates; Nova Scotia Consumer Advocate. October 2010.

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

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

Revenue-allocation and rate design. DSM program.

257. **N.S. UARB** M03665, Nova Scotia Power depreciation rates; Nova Scotia Consumer Advocate. February 2011.

Depreciation and rates.

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

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

259. **N.S. UARB** M03665, depreciation rates of Nova Scotia Power; Nova Scotia Consumer Advocate. February 2011.

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

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

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

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

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

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

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

263. **N.S. UARB** M04104; Nova Scotia Power general rate application; Nova Scotia Consumer Advocate. August 2011.

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

264. **N.S. UARB** M04175, Load-retention tariff; Nova Scotia Consumer Advocate. August 2011.

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

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

Structuring energy-efficiency programs for large customers.

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

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

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

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

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

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

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

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

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

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

271. **N.S. UARB** M04819, demand-side-management plan of Efficiency Nova Scotia; Nova Scotia Consumer Advocate. May 2012.

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

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

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

273. **N.S. UARB** M04862, Port Hawksbury load-retention mechanism; Nova Scotia Consumer Advocate. June 2012.

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

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

Cost allocation. Estimation of marginal customer costs.

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

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

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

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

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

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

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

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

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

Estimation of marginal costs. Fuel switching.

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

Economic and financial modeling of investment. Treatment of AFUDC.

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

Revenue requirements. Allocation of tax benefits. Ratemaking.

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

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

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

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

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

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

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

Cost-allocation and rate design.

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

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

287. **Conn. PURA** Docket No. 14-01-01, Connecticut Light and Power Procurement of Standard Service and Last-Resort Service. July and October 2014.

Proxy for review of bids. Oversight of procurement and selection process.

288. **Conn. PURA** Docket No. 14-01-02, United Illuminating Procurement of Standard Service and Last-Resort Service. January, April, July, and October 2014.

Proxy for review of bids. Oversight of procurement and selection process.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

296. **Québec Régie de L'énergie** R-3867-2013 phase 1, Gaz Métro cost allocation and rate structure; ROEÉ. February 2015

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

297. **Conn. PURA** Docket No. 15-01-01, Connecticut Light and Power Procurement of Standard Service and Last-Resort Service. February and July 2015.

Proxy for review of bids. Oversight of procurement and selection process.

298. **Conn. PURA** Docket No. 15-01-02, United Illuminating Procurement of Standard Service and Last-Resort Service. February, July, and October 2015.

Proxy for review of bids. Oversight of procurement and selection process.

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

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

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

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

301. **Mich. PSC** U-17767, DTE Electric Company rates; Michigan Environmental Council, Sierra Club, and Natural Resource Defense Council. May 2015.

Cost effectiveness of pollution-control retrofits versus retirements. Market prices. Costs of alternatives.

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

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

303. **Penn. PUC** P-2014-2459362, Philadelphia Gas Works DSM, universal-service, and energy-conservation plans; Philadelphia Gas Works. Direct, May 2015; Rebuttal, July 2015.

Avoided costs. Recovery of lost margin.

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

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

305. **PUC Ohio** 14-1693-EL-RDR, AEP Ohio Affiliate purchased-power agreement, Sierra Club. September 2015.

Economics of proposed PPA, market energy and capacity projections. Risk shifting. Lack of price stability and reliability benefits. Market viability of PPA units.

306. **N.S. UARB** M06214, NS Power Renewable-to-Retail rate, Nova Scotia Consumer Advocate. November 2015.

Review of proposed design of rate for third-party sales of renewable energy to retail customers. Distribution, transmission and generation charges.

307. **PUC Texas** Docket No. 44941, El Paso Electric rates; Energy Freedom Coalition of America. December 2015.

Cost allocation and rate design. Effect of proposed DG rate on solar customers. Load shapes of residential customers with and without solar. Problems with demand charges.

308. **N.S. UARB** M07176, NS Power 2016 Capital Expenditures Plan, Nova Scotia Consumer Advocate. February 2016.

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

309. **Md. PSC** 9406, BGE Application for recovery of Smart Meter costs, Maryland Office of People's Counsel. Direct February 2016, Rebuttal March 2016, Surrebuttal March 2016.

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

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

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

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

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

312. **Md. PSC** 9418, PEPCo Application for recovery of Smart Meter costs, Maryland Office of People's Counsel. Direct July 2016, Rebuttal August 2016, Surrebuttal September 2016.

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

313. **Md. PSC** 9424, Delmarva P&L Application for recovery of Smart Meter costs, Maryland Office of People's Counsel. Direct September 2016, Rebuttal October 2016, Surrebuttal October 2016.

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

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

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

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

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

316. **N.S. UARB** M07745, NS Power 2017 Capital Expenditures Plan, Nova Scotia Consumer Advocate. January 2017.

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

317. **N.S. UARB** M07746, NS Power Enterprise Resource Planning project, Nova Scotia Consumer Advocate. February 2017.

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

318. **N.S. UARB** M07767, NS Power Advanced Metering Infrastructure projects, Nova Scotia Consumer Advocate. February 2017.

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

319. **Québec Régie de l'énergie** R-3867-2013 phase 3A; Gaz Métro estimates of marginal O&M costs; ROEÉ. March 2017.

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

320. **N.S. UARB** M07718, NS Power Maritime Link Cost Recovery, Nova Scotia Consumer Advocate. April 2017.

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

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

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

322. **PUCO** 16-1852, AEP Ohio Electric Security Plan, Natural Resources Defense Council. May 2017.

Residential customer charge. Cost causation. Effect of rate design on consumption.

323. **Iowa Utilities Board** RPU-2017-0001, Interstate Power and Light rate case, Natural Resources Defense Council. Direct August 2017, Reply September 2017.

Critique of proposed demand-charge pilot rates for residential and small commercial customers. Defects of demand rates and shortcomings of IPL experimental proposal design.

324. **N.S. UARB** M08087, NS Power 2017 Load Forecast, Nova Scotia Consumer Advocate. Direct August 2017.

Review of forecast methodology, including extrapolation of drivers of commercial load from US national data; treatment of non-firm and competitive loads; behind-the-meter generation and controlling peak-load growth.

325. **Québec Régie de l'énergie** R-3867-2013 phase 3B; Gaz Métro line-extension policy; ROEÉ. September 2017.

The costs of adding new load. Estimating the durability of revenues from line extensions.

326. **Mass. EFSB** 17-02; Eversource proposed Hudson-Sudbury transmission line; Town of Sudbury. Direct October 2017, Supplemental January 2018..

Accuracy of ISO New England regional load forecasts. Potential for distributed solar, storage and demand response.

327. **Manitoba PUB**, Manitoba 2017/18 & 2018/19 General Rate Application; Green Action Coalition. October 2017.

Marginal costs. Rate design. Affordability rate design for low-income and electric-heating customers. Design of residential inclining blocks. Problems with demand charges and demand ratchets. Cost-of-service study improvements.

328. **N.S. UARB** M08383, NS Power 2018 Annually Adjusted Rates; Consumer Advocate. January 2018.

Projection of incremental dispatch cost. Computing administrative charges. Methodological issues.

329. N.S. UARB M08349, NS Power's Advanced Metering Infrastructure Proposal; Consumer Advocate. January 2018.

Estimation of AMI benefits: load balancing among feeders, critical peak pricing, avoided costs of meters for distributed generation. NS Power's claims of benefits from accounting credits (AFUDC, overheads, and converting write-offs to reduced revenue) and shifting costs to customers (earlier billing, higher recorded usage). Realistic AMI meter life. Excessive charge for customers who opt out of AMI.

330. N.S. UARB M08350, NS Power 2018 Annual Capital Expenditures Plan; Consumer Advocate. February 2018.

Overlap between ACE projects and AMI project. Hydro project planning and valuation of lost hydro energy output.

331. Conn. PURA Docket No. 08-01-01RE05, Proposed Amendment to Peaker Contracts; Connecticut Consumers Counsel. May 2018.

Dividing increased revenues from ISO-NE's Pay-for-Performance mechanism between contract generators and ratepayers.

332. Kansas CC Docket No. 18-WSEE-328-RTS, Westar Rate Case; Sierra Club. Direct June 2018. Rebuttal June 2018. Supplement July 2018.

Costs and benefits of running Westar coal plants. Costs of renewables and other alternatives. Recommendation regarding planning, coal retirement schedule, and acquisition of leased capacity.

333. Cal. PUC Application 17-09-006; Pacific Gas and Electric Gas Cost Allocation Proceeding; Small Business Utility Advocates. Direct June 2018.

Allocation of gas distribution system costs. Allocation of costs of energy-efficiency programs.

334. N.S. UARB M08670, NS Power 2018 Load Forecast, Nova Scotia Consumer Advocate. Direct July 2018.

Review of forecast methodology, including treatment of future energy-efficiency programs, treatment of third-party supply and behind-the-meter generation.

335. Iowa Utilities Board RPU-2018-0003, MidAmerican Energy Request for Approval of Ratemaking Principles for Wind XII; Sierra Club. Direct August 2018.

Cost and benefits of continued operation of six MidAmerican coal-fired units.

336. Cal. PUC A.18-02-016, 03-001, 03-002; 2018 Energy Storage Plans; Small Business Utility Advocates. Direct, Rebuttal and Supplement, August 2018.

Reliance on substation-sited storage. Need for increased emphasis on customer-sited and shared storage. Maximizing benefits, total and for small business. Oversized SDG&E proposed projects. Cost recovery. Storage technology diversity.

337. La. PSC U-34794; Cleco Corp Purchase of NRG Assets and Contracts; Sierra Club. Direct, September 2018.

Economics of NRG generation resources, Cleco Power coal plants and wholesale sales contracts. Risks of the proposed transaction.

338. Cal. PUC A.18-11-005; Southern California Gas Demand-Response Proposal; Small Business Utility Advocates. Direct March 2019, Rebuttal April 2019.

Potential benefits of gas demand response and SoCalGas failure to identify potential benefits from its programs. Program design. Cost allocation.

339. Cal. PUC A.18-11-003; Pacific Gas & Electric Electric Vehicle Rate; Small Business Utility Advocates. Direct April 2019, Rebuttal May 2019.

Critique of subscription demand charge. Time-of-use periods. Outreach to small business. Time-of-use price differentials.

340. Cal. PUC A.18-07-024; Southern California Gas and San Diego Gas & Electric Triennial Cost Allocation Proceeding; Small Business Utility Advocates. Direct April 2019.

Core commercial declining blocks. Computation of customer charges. Embedded versus marginal cost allocation. Marginal cost computation. Allocation of self-generation incentives.

341. Vt. PUC 19-0397-PET; Screening Values for Energy-Efficiency Measures; Conservation Law Foundation. Direct May 2019.

Conceptual basis for including price-suppression benefits to consumers. Avoided T&D costs. Avoided externalities with a renewable energy standard. Risk mitigation.

342. N.S. UARB M09096; EfficiencyOne Application for 2020–2022 DSM Plan; Consumer Advocate. May 2019

Evaluate NS Power critique of EfficiencyOne proposal. Comparability of efficiency budgets. Affordability. Energy-efficiency programs and resource planning.

343. N.S. UARB M09191; NS Power 2019 Load Forecast Report; Consumer Advocate. July 2019.

Review load-forecast treatment of energy efficiency, fuel switching, electric vehicles, behind-the-meter solar, AMI-enabled programs, and the changing trend in lighting efficiency.

344. **Iowa Utilities Board** RPU-2019-001; Interstate Power and Light Rate Case; Sierra Club. Direct August 2019; Rebuttal September 2019.

Economics of continued operation of five coal units: fuel, O&M, capital additions, overheads, market revenues, and cost of renewable resources. Recommend retirement of all units.

345. **Maine PUC** 2019-00101; Unitil Precedent Agreement for Westbrook Xpress, Conservation Law Foundation. August 2019.

The role of fuel convserions in Unitil's load forecast. Mandates for reducing greenhouse gas emissions. Efficient electric end uses as alternatives to gas system expansion. Risks of and alternatives to new pipeline supply.

346. **Maine PUC** 2019-00105; Bangor Natural Gas Precedent Agreement for Westbrook Xpress, Conservation Law Foundation. August 2019.

Mandates for reducing greenhouse gas emissions. Efficient electric end uses as alternatives to gas system expansion. Risks of and alternatives to new pipeline supply.

347. **Wisconsin PSC 6690-UR-126**; Wisconsin Public Service Corporation 2020 Rate Case, Sierra Club. Direct August 2019, Surrebuttal October 2019.

Economics of continued operation of four coal units: fuel, O&M, capital additions, overheads, market revenues, and cost of renewable resources. Recommend retirement of uneconomic units.

348. **Wisconsin PSC 05-UR-109**; Wisconsin Electric Power Company2020 Rate Case; Sierra Club. Direct August 2019, Surrebuttal October 2019

Economics of continued operation of six coal units: fuel, O&M, capital additions, overheads, market revenues, and cost of renewable resources. Recommend retirement of uneconomic units.

349 **N.S. UARB M09277**; NS Power Maritime Link Cost Recovery, Nova Scotia Consumer Advocate. August 2019.

Benefits of the Maritime Link transmission line prior to operation of associated power supply and connecting transmission facilties.

350. **N.H. PUC** DG 17-198; Liberty Utilities Petition to Approve Firm Supply, Transportation Agreements, and the Granite Bridge Project; Conservation Law Foundation. September 2019.

Need for transportation contracts and new pipeline. Alternative of switching oil and propane to efficient electric end uses. Limited life of gas infrastructure and effect on ratepayer costs.

351. Colorado PUC 19AL-0268E; Public Service of Colorado Rate Case; Sierra Club. September 2019.

Prudence of management of superheater tube failures. Unfavorable economics of coal plants nationally. Need for continuing review of coal-plant economics and benefits of retirement.

352. N.H. PUC DG 17-152; Liberty Utilities Least Cost Integrated Resource Plan; Conservation Law Foundation. September 2019.
Integrated planning for gas utilities in an era of carbon constraints. Heat pump electrification versus gas conversion of oil-fired space and water heating.

353. N.S. UARB M09420; NS Power Application for an Extra-Large Industrial Active Demand Control Tariff; Nova Scotia Consumer Advocate. December 2019.

Estimating incremental costs, including lost wheeling revenues, variable O&M, and variable capital cost; updating and reconciliation of incremental costs.

354. Cal. PUC A.19-07-006; San Diego Gas & Electric Fast-Charging and Heavy-Duty Electric Vehicle Proposal; Small Business Utility Advocates. Direct January 2020, Rebuttal February 2020.

Interim rate proposal. Critique of subscription and demand charges. Time-of-use periods. Recovery of lost revenues.

355. N.S. UARB M09519; NS Power Smart Grid Application; Nova Scotia Consumer Advocate. February 2020. Joint testimony with John D. Wilson.

Differentiating capital costs from expenses. Inclusion of decommissioning costs in project plan. Selection of the Distributed Energy Resources Management System.

356. N.S. UARB M09499; NS Power 2020 Annual Capital Expenditure Plan; Nova Scotia Consumer Advocate. February 2020. Joint testimony with John D. Wilson.

Planning for hydro life extension or retirement. Appropriate levels of contingency in project budgets. Aggregation of multi-year capital programs. Cost-control efforts.

357. Cal. PUC A.19-03-002; San Diego Gas & Electric General Rate Application, Phase 2; Small Business Utility Advocates. Direct March 2020; Rebuttal May 2020.

Problems with proposed increases in the Monthly Service Fees and reliance on demand charges in for medium non-residential customers. Improving hours for the TOU periods.

358. **N.S. UARB** M09609; NS Power Authorization to Overspend on Gaspereau Dam Works; Nova Scotia Consumer Advocate. May 2020. Joint testimony with John D. Wilson.

Alternatives to the proposed project, including decommissioning the affected hydro system. Choice of project contingency factor. Estimation of archaeological costs. Replacement energy cost assumptions.

359. **N.S. UARB** M09609; NS Power Advanced Distribution Management System Upgrade; Nova Scotia Consumer Advocate. May 2020. Joint testimony with John D. Wilson.

Need for the ADMS. Integration with the Distributed Energy Resources Management System.

360. **Cal. PUC** A.19-10-012; San Diego Gas & Electric Power Your Drive Electric Vehicle Charging Program; Small Business Utility Advocates. Direct May 2020; Rebuttal June 2020. Joint testimony with John D. Wilson.

Ensuring that utility-installed chargers advance California goal for electric vehicles. Budget controls. Reporting requirements. Evaluation, monitoring and verification processes. Outreach to small business customers.

361. **N.S. UARB** M09499; Authorization to Overspend for Various Distribution Routines; Nova Scotia Consumer Advocate. June 2020.

Guidelines for reporting cost overruns due to extreme weather. Documentation of drivers of equipment deterioration and replacement. Tracking costs of connecting new customers.

362. **N.S. UARB** M09499; NS Power 2020 Load Forecast Report; Nova Scotia Consumer Advocate. July 2020. Joint testimony with John D. Wilson.

Impacts of the COVID-19 recession on load. Additional appropriate end-use studies. Improvements to modelling of electrification and factors. Effects of AMI and time-varying pricing on data availability and load.

363. **Cal. PUC** A.20-03-002, et al; Pacific Gas & Electric, Southern California Edison and San Diego Gas & Electric 2020 Energy Storage Procurement and Investment Plans; Small Business Utility Advocates. Direct and Rebuttal September 2020.

Adequacy of transmission, distribution and customer-side storage acquisition. Extending residential smart water-heater and new-home storage programs to small commercial customers.

ACRONYMS AND INITIALISMS

APS	Alleghany Power System
ASLB	Atomic Safety and Licensing Board
BEP	Board of Environmental Protection
BPU	Board of Public Utilities
BRC	Board of Regulatory Commissioners
CC	Corporation Commission
CMP	Central Maine Power
DER	Department of Environmental Regulation
DPS	Department of Public Service
DQE	Duquesne Light
DPUC	Department of Public Utilities Control
DSM	Demand-Side Management
DTE	Department of Telecommunications and Energy
EAB	Environmental Assessment Board
EFSB	Energy Facilities Siting Board
EFSC	Energy Facilities Siting Council
EUB	Energy and Utilities Board
FERC	Federal Energy Regulatory Commission
ISO	Independent System Operator
LRAM	Lost-Revenue-Adjustment Mechanism
NARUC	National Association of Regulatory Utility Commissioners
NEPOOL	New England Power Pool
NRC	Nuclear Regulatory Commission
OCA	Office of Consumer Advocate
PSB	Public Service Board
PBR	Performance-based Regulation
PSC	Public Service Commission
PUC	Public Utility Commission
PUB	Public Utilities Board
PURA	Public Utility Regulatory Authority
PURPA	Public Utility Regulatory Policy Act
ROEÉ	Regroupement des organismes environnementaux en énergie
SCC	State Corporation Commission
UARB	Utility and Review Board
USAEE	U.S. Association of Energy Economists
UC	Utilities Commission
URC	Utility Regulatory Commission
UTC	Utilities and Transportation Commission

PLC 10/23/2020

Exhibit PLC-2

Demand-Reduction-Induced Price Effects for PGW

Paul Chernick
Resource Insight, Inc.
August 20, 2015

Table of Contents

Wholesale Gas Market Effects

Supply Market Effects on PGW Gas Bills

Reducing gas usage reduces the price of natural gas on a continental basis. Table 1 summarizes the results of a number of analyses in the period 1998–2007 that estimated the effect on continental gas prices of reducing gas use with gas or electric energy-efficiency programs and/or renewable energy.[1] Most of these studies used EIA's National Energy Modeling System (NEMS), which is also used in the Annual Energy Outlook.[2] Table 1 shows results for 2020, except for the ACEEE study, which estimated results in 2008.

Most of these analyses estimated that a 1% reduction in US gas consumption would reduce gas prices by about 1%–3%. For the gas supply prices that we are projecting for 2014–2020, a price reduction of 1%–3% would be about $0.05–$0.20/Dth. For that same time period, EIA forecasts that total US consumption of natural gas will be about 25 quads (or billion Dth). In more practical terms, the reduction of PGW gas consumption by 1% (about 780,000 Dth) would reduce continental gas prices by about $0.0002–$0.0006/Dth.

[1] While there are regional differences in gas prices due to pipeline congestion, most of the natural-gas price in most locations at most times is determined by the total balance of load and supply across the US and Canada.

[2] The ACEEE study used the proprietary model of Energy and Environmental Analysis, Inc.

Table 1: Estimates of Gas Price Suppression from Reduced Usage

Author	Reduction in U.S. Gas Consumption quads	Gas Wellhead Price Reduction $/Dth (2000$)	$/Dth per quad (2000$)
EIA (1998)	1.12	$0.34	$0.30
EIA (1999)	0.41	$0.19	$0.46
EIA (2001)	1.45	$0.27	$0.19
EIA (2001)	3.89	$0.56	$0.14
EIA (2002a)	0.72	$0.12	$0.17
EIA (2002a)	1.32	$0.22	$0.17
EIA (2003)	0.48	$0.00	$0.00
UCS (2001)	10.54	$1.58	$0.15
UCS (2002a)	1.28	$0.32	$0.25
UCS (2002a)	3.21	$0.55	$0.17
UCS (2002b)	0.72	$0.05	$0.07
UCS (2003)	0.10	$0.14	$1.40
UCS (2004a)	0.49	$0.12	$0.24
UCS (2004a)	1.80	$0.07	$0.04
UCS (2004b)	0.62	$0.11	$0.18
UCS (2004b)	1.45	$0.27	$0.19
Tellus (2002)	0.13	$0.00	$0.00
Tellus (2002)	0.23	$0.01	$0.04
Tellus (2002)	0.28	$0.02	$0.07
ACEEE (2003)	1.35	$0.76	$0.56

The structure of natural gas supply has changed considerably since 2007, with the growing importance of shale gas and the transition from forecasts of large LNG imports to forecasts of significant LNG exports. As a result, we have not used these older analyses to estimate gas-supply DRIPE. Instead, we have used sensitivity analyses the EIA ran for the 2012 and 2014 AEOs.

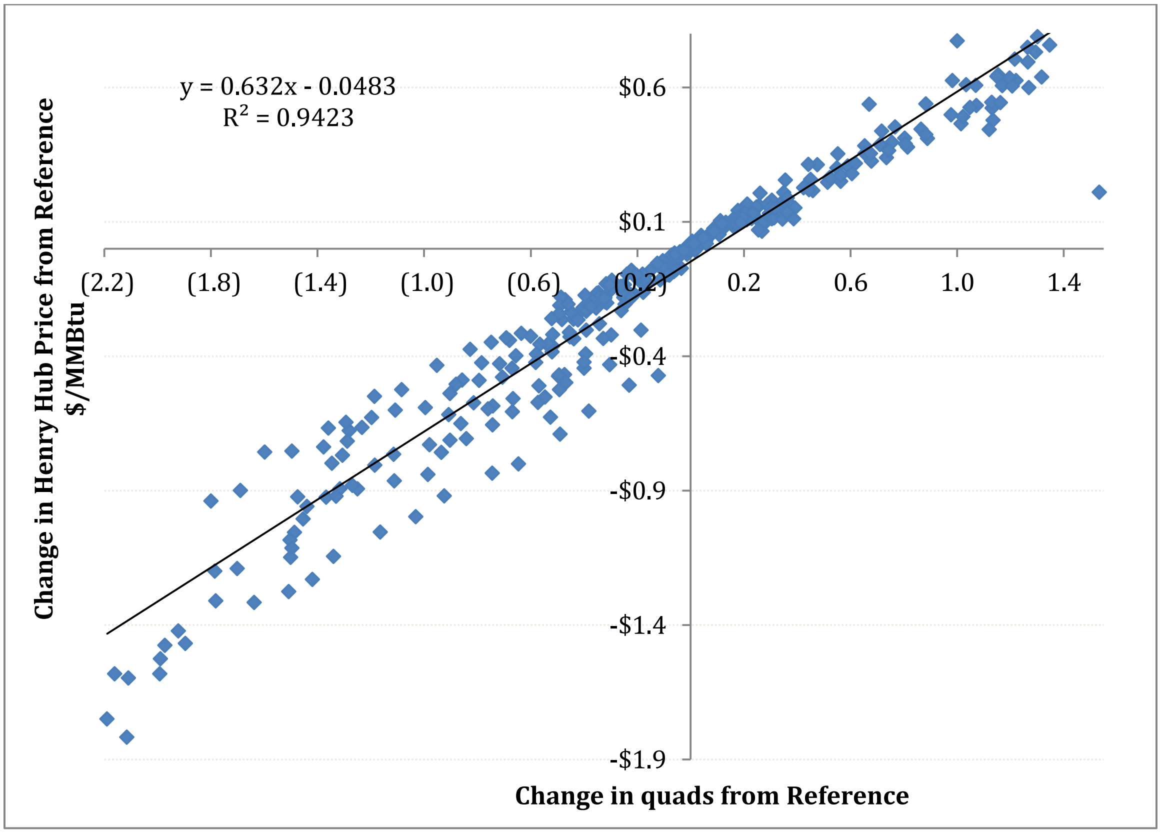
Table 2 lists the AEO cases that change natural gas demand without affecting the gas supply curve, along with EIA's projection of the changes in gas consumption (in quads or billion Btu or trillion cubic feet), and Henry Hub price (in 2010$/Dth or 2012$/Dth) from the AEO reference case in 2020.

Table 2: AEO Gas-Demand Sensitivity Cases

Forecast Case	AEO 2012 Changes from 2020 Reference Case		AEO 2014 Changes from 2020 Reference Case	
	Consumption (Quads)	Henry Hub (2010$/Dth)	Consumption (Quads)	Henry Hub (2012$/Dth)
High economic growth	0.48	0.31	0.93	0.22
Low economic growth	-0.53	-0.35	-0.90	0.14
Low nuclear	0.07	0.05		
High nuclear	0	0.01	-0.19	-0.01
Low coal cost	-0.32	-0.2	-0.38	-0.07
High coal cost	0.45	0.26	0.64	0.17
Residential & commercial demand technology				
Existing	0.37	0.17	0.78	0.25
High	-0.49	-0.47	-0.94	0.12
Best	-0.74	-0.83	-1.28	0.08
High coal retirement	0.36	0.17	1.25	0.37
Low renewable cost	-0.08	-0.1	-0.17	-0.01
Extended taxes and standards for efficiency & renewables	-0.15	-0.08	0.23	0.15
No sunset on tax policies for efficiency & renewables	-0.06	-0.02	0.21	0.01

Figure 1 plots those changes from the reference case, over all the years reported in AEO 2012. The 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.

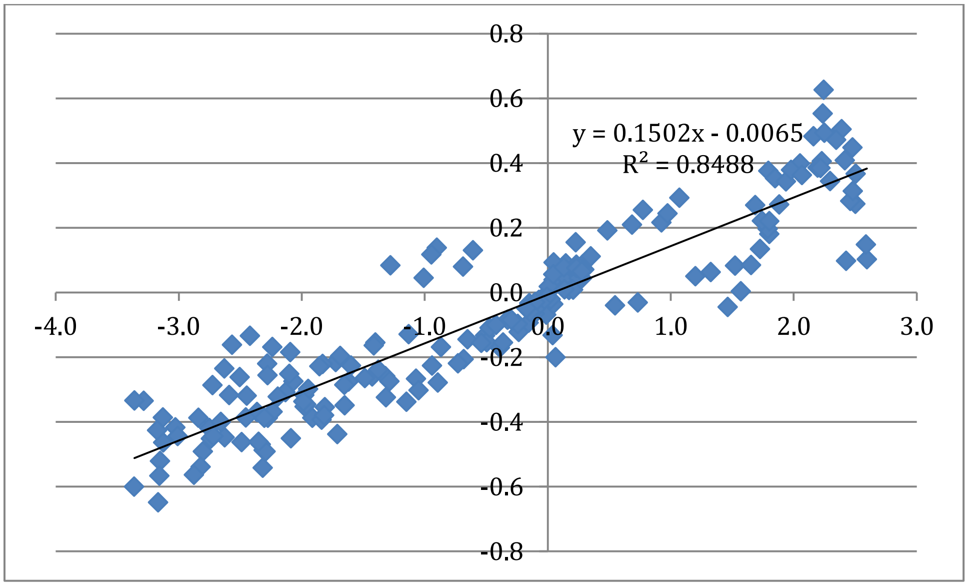
Figure 1: Gas Demand and Price Changes, AEO 2012



The linear trend line in Figure 1, which implies a $0.632/Dth decrease in Henry Hub gas price (in 2010$) for every quad (billion Dth) decrease in annual gas consumption. Esclated to 2012 dollars, this slope equals $0.650/Dth, assuming a total of 3% inflation over these two years. This rate from the 2012 AEO is of greater magnitude than the comparable slope calculated from the 2014 AEO.

Interestingly, the same cases in 2014 had greater changes in natural gas demand and lower changes in Henry Hub price. Figure 2 plots those changes from the reference case, over all the years reported in AEO 2014.

Figure 2: Gas Demand and Price Changes, AEO 2014



The regression line in Figure 2 implies a \$0.15/Dth decrease in Henry Hub gas price for every quad decrease in annual gas consumption – roughly a quarter of the slope in the 2012 sensitivities. Lacking any compelling reason to assume that one of these analyses is better suited to this study than the other, it is reasonable to assume that the effect of consumption on supply prices is around the simple average of the two cases, or \$0.40/Dth per quad.

The AEO data do not appear to show any significant decay in the price-reduction values over time. The AEO gas prices (at least after the first few years) reflect the full long-term costs of gas development, not just the operation of existing wells. The shape of the scatter plots in Figure 1 and Figure 2 do not suggest strong effects of either decay (which would produce an S curve, with the out years leveling off) or accumulating effects (which would result in the curves becoming steeper in the out years, more extreme than the trend lines). Such accumulation could result from the effect of usage rates on the marginal cost of extraction for a finite resource.[3] Lower gas usage in 2016 would leave more low-cost gas in the ground to meet demand in 2017, causing the effect to accumulate over time. A program that saves 100 Dth annually from 2015 onward would have kept another 500 BBtu in the ground by 2020, in addition to reducing 2020 demand by 100 BBtu. This accumulation may offset any factors that would reduce the price effect over time.

The effect of this change in price on consumer bills is the product of the \$0.40/Dth per quad times the annual gas use by the relevant consumers. Since PGW's end-use gas sendout for

---

[3] As technology changes, the size of the resource changes, but once gas is removed from the ground, it is gone forever. Less gas will be available from that play in the future, forcing the marginal supply to more expensive plays.

FY2014 was about 80.5 million Dth, the potential effect on PGW gas end users' gas supply bill of one Dth reduction in gas consumption is

$$(\$0.40 \times 10^{-9}/\text{Dth}) \times (0.0805 \times 10^{9}\ \text{Dth}) = \$0.032/\text{Dth saved.}$$

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 is about 582 million Dth, producing statewide benefits of $0.233/Dth.

Effect of Supply Gas Prices on Electric Prices

Natural gas set the market price in PJM about 36% of the time in calendar 2014.[4] That number is likely to rise over the next several years, as coal plants retire. The PJM data on marginal fuels reflect the generators that are at the margin in various zones of the sprawling PJM footprint, which stretches from Virginia to Chicago. In some hours, different fuels set the prices in different zones. Considering the large amount of coal-fired and wind-fired generation in the western parts of PJM, the percent of hours in which gas sets prices in Pennsylvania (and especially eastern Pennsylvania) is likely to be higher than the average.

When gas sets the market electric price, every $1/Dth change in gas price would change the market price by $7/MWh for the most efficient combined-cycle plants, $10/MWh for modern combustion turbines and older steam plants, and up to $15/MWh for older peakers. In 2014, PECo delivered about 37.5 million MWh. Assuming the average heat rate for the marginal gas generators is 9.5 Dth/MWh, the savings to PECo customers (many of which are also PGW customers and Philadelphia residents or businesses) from a Dth reduction in gas use would be

$$(\$0.4\times10^{-9}/\text{Dth}) \times (9.5\ \text{Dth/MWh}) \times 37.5\times10^{6}\ \text{MWh} \times 36\% = \$0.051/\text{Dth}$$

For all of Pennsylvania, with deliveries of about 146.3 million MWh, lower gas supply prices would save customers statewide about $0.20 for every MMBtu saved.

Effect of Gas Conservation on Pipeline Charges

Just as reducing gas consumption reduces gas prices at the wellhead and Henry Hub, reducing gas consumption also reduces the difference (or basis) between the market prices at Henry Hub and the Philadelphia citygate. This reduction in market price has no effect on the costs to PGW gas customers, because PGW purchases its gas transportation services under long-term contracts at tariff rates. For third-party marketers setting prices for their customers, and for power plants setting their bid prices, the market prices represent the cost of acquiring capacity or the opportunity cost of not selling the capacity into the market.

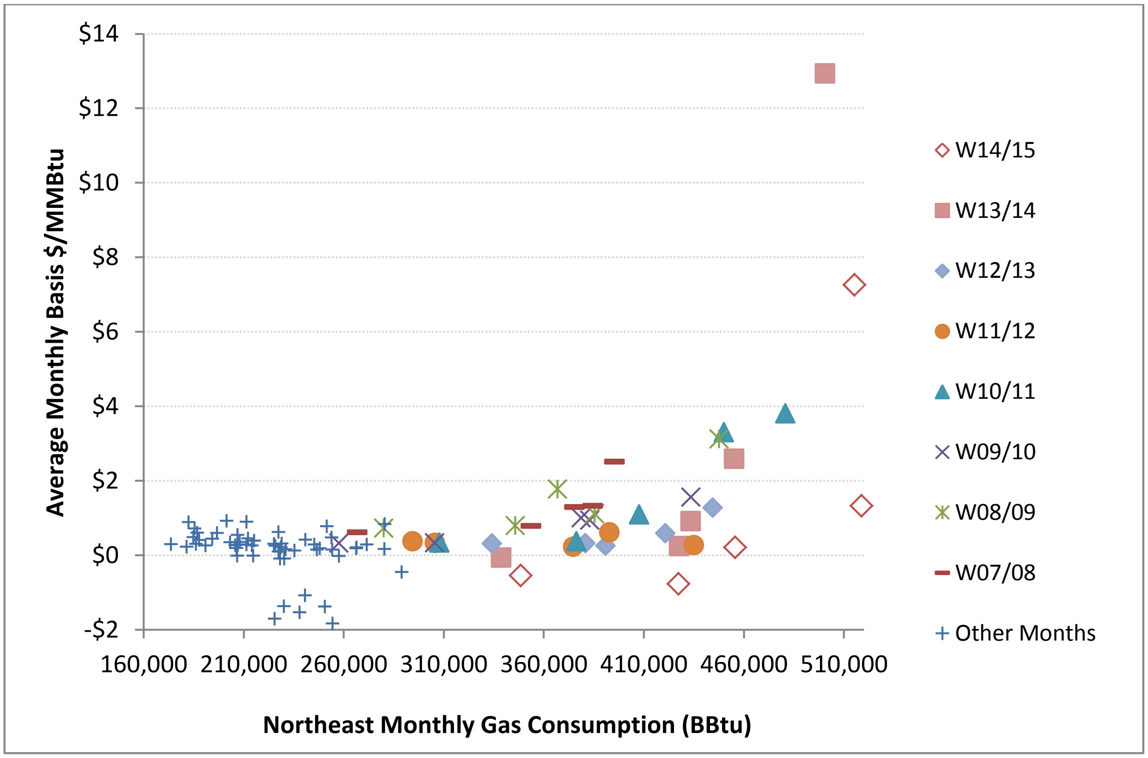
[4] Data from http://www.monitoringanalytics.com/data/marginal_fuel.shtml.

Figure 3 plots the basis from Henry Hub to Texas Eastern Zone M-3 against monthly gas consumption in the Northeast (Pennsylvania, New Jersey, New York, Massachusetts, Rhode Island, Connecticut and New Hampshire) for each month from January 2008 through March 2015, the last month for which EIA has reported reasonably complete state consumption data.[5] The solid markers identify the data for November through March for each of the indicated winters.

Basis has mostly been under $0.50/Dth (reflecting pipeline commodity and fuel charges) for consumption under 350,000 BBtu/month. The four non-winter months with basis over $0.50/Dth were April–July 2008, when gas prices were in the range of $12–$13/Dth, which would have substantially increased the fuel charges and hence the total variable pipeline charge. Since 2013, basis has been negative in summer and other low-load months, as shale gas production has pushed prices in western Pennsylvania below the prices at Henry Hub. Over about 350,000 BBtu/month, basis has risen fairly steadily for higher consumption levels, with lower prices in the unusually mild winter of 2011/12.

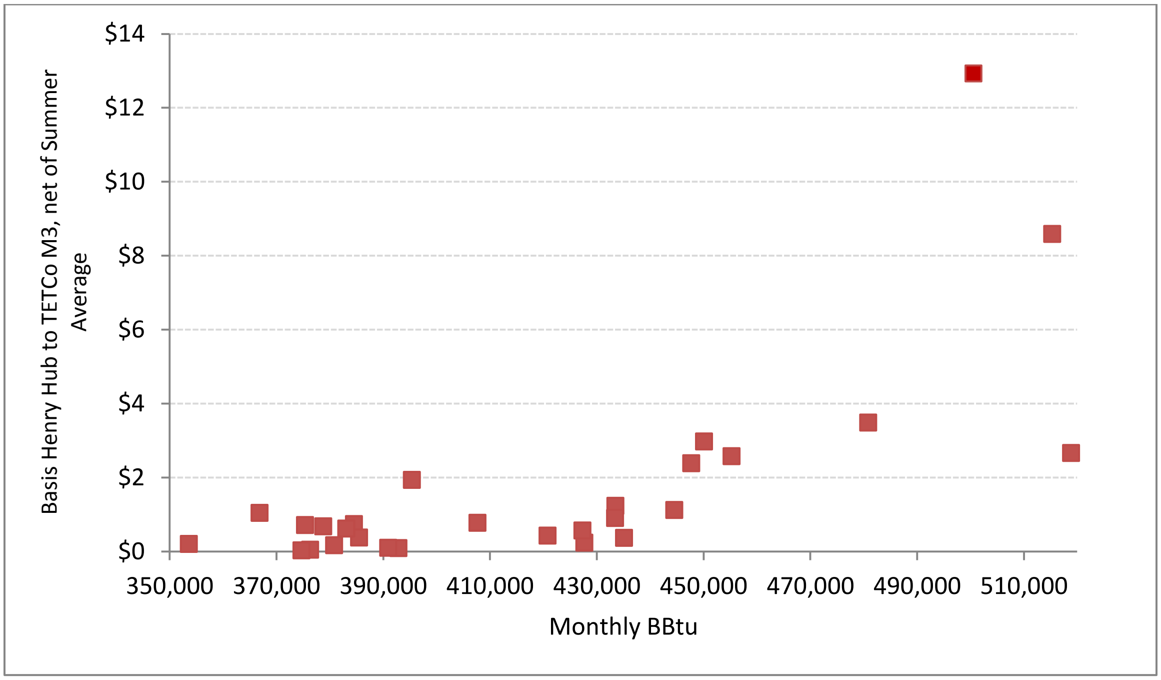
[5] Vermont and Maine have been served entirely or primarily from Canada, and are not included in this analysis. I interpolated load for New Jersey in August 2014, New York in September 2015, and New Hampshire in March 2015, which EIA has not yet reported. The summer months do not affect the subsequent analysis and the New Hampshire load is very small, about 1.5% of the total, so any error in that extrapolation would not be material.

Figure 3: TETCo M-3 Basis versus Northeast Gas Consumption



Since gas prices to the west of the TETCo M3 hub have been falling, compared to Henry Hub, I normalized the basis data in Figure 3 by subtracting the average basis in the previous summer (April through October) from the winter monthly basis. Figure 4 shows the results. Basis is higher than the summer average for all the winter months with load over 350,000 BBtu, but a clear upward trend is difficult to observe until deliveries rise above 400,000 BBtu. Recall that a month with 360,000 MM BBtu f may have 30 days at 12,000 BBtu /day (which would likely have little congestion), or 15 uncongested days at 8,000 BBtu /day and 15 highly congested days at 16,000 BBtu/day, or many other combinations of high- and low-load days. Since data on daily gas demand is difficult to assemble, I have not been able to examine the effect of load on basis at a level more detailed than the monthly EIA data.

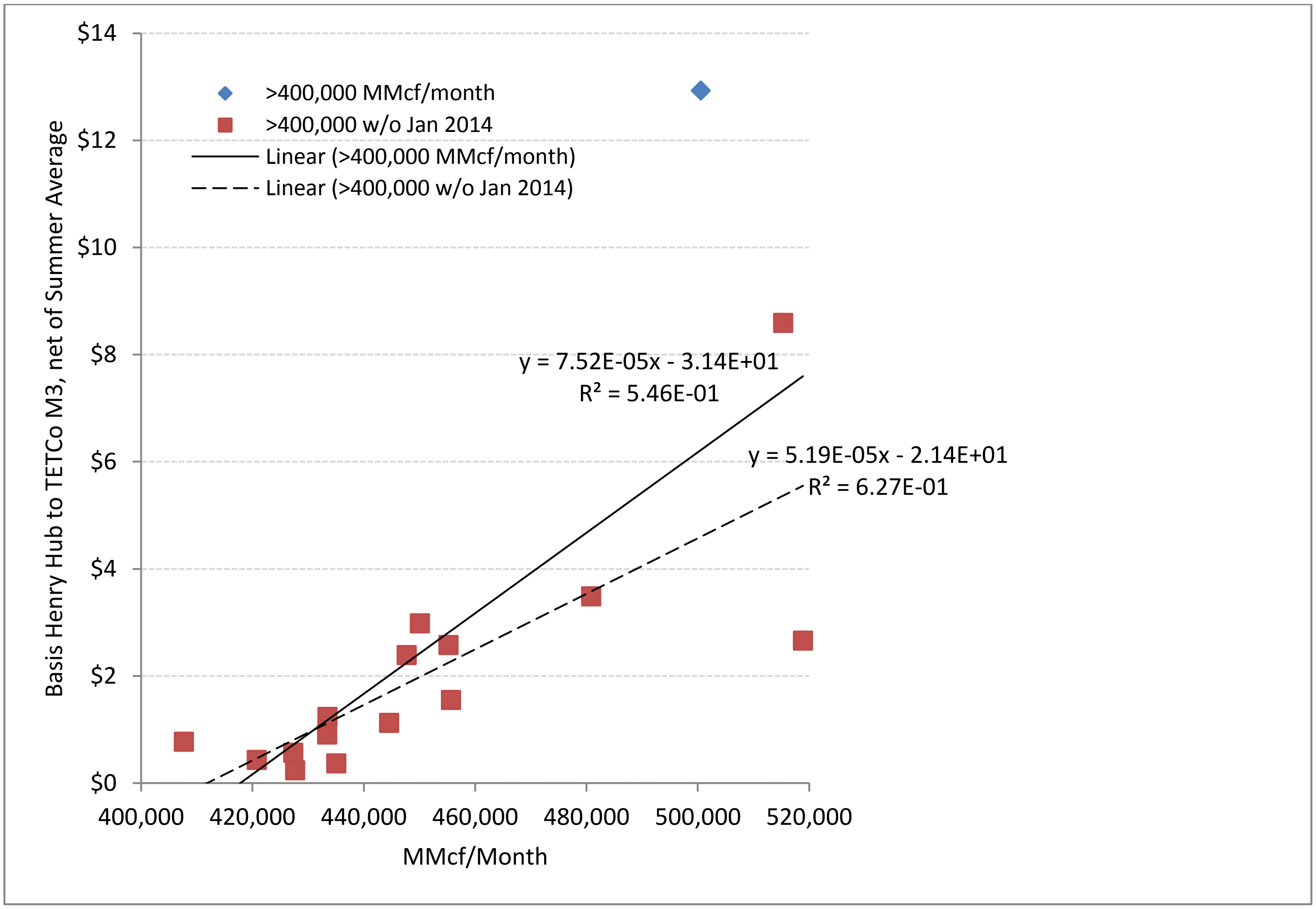
Figure 4: Increase in Basis Versus Monthly Northest Load



As shown in Figure 5, every BBtu of monthly consumption over 400,000 BBtu/month has been associated with a $0.075/Dth average increase in the monthly basis. One data point stands out: the January 2014 basis is twice the trend-line value. Without January 2014, the relationship between throughput and basis falls to $0.052/Dth per BBtu/month. While January 2014's basis was exceptional, there is no reason why another basis blowout could not occur. Hence, a reasonable range of basis DRIPE coefficients is about $0.052 to $0.075/Dth per BBtu/month.

The >400,000 BBtu/month load range includes December, January and February and March in the last two winters. Since the EIA projects roughly stable gas demand loads for New England and the Northeast, it seems reasonable to assume that load will continue to affect basis in those months.

Figure 5: TETCo M-3 Basis versus Northeast Gas Consumption, High Loads



Local Basis DRIPE

Gas distribution companies (and particularly PGW) primarily purchase gas for their full-service sales customers in supply areas (the Appalachians, the Gulf Coast) and ship it to their city gates at regulated pipeline rates. Their costs are not influenced significantly by the market basis, since they are not purchasing transportation services at market rates. Transportation customers (or the marketers serving them), on the other hand, purchase primarily market supplies (at daily spot prices or at futures prices months or years in advance), and electric generators, with their highly variable requirements, purchase almost exclusively in the daily spot market.

Multiplying the low price-suppression coefficient ($0.052/Dth per monthly TBtu) by PGW's average monthly transportation deliveries forecast for December 2015 to March 2016 (2.86 TBtu), weighted by the fraction of an annual space-heating Dth used in the average winter month (about 18%) gives a price-suppression benefit of about $0.027/Dth of saved gas. The corresponding benefit for the high coefficient would be $0.039/Dth. For my subsequent computations, I will use the average, or $0.033/Dth.

For baseload measures, for which only about 8% of the gas savings occur in each winter month, the range of benefits to PGW transportation customers would be $0.012 to $0.018/Dth saved, or an average of $0.015/Dth.

Assuming that contract durations average three years, the aggregate price benefit accruing to PGW transportation customers would be about $0.011/Dth in the first year, $0.022/Dth in the second year, and $0.033/Dth thereafter. A Dth reduction in baseload gas usage would reduce winter load less than half as much, about $0.005/Dth in the first year, $0.010/Dth in the second year, and $0.015/Dth thereafter.

Similarly, the price effect on electricity prices for PECo customers would be $0.052–$0.075/Dth per TBtu, times the percentage of hours with gas at the margin (about 40%), times a 9.5 heat rate, times PECo monthly sales in the winter (averaging about 3,600 GWh), weighted by the percentage of PGW heating load in the average winter months, would result in total electric price effects of about $0.13–$0.19/Dth for space-heating savings and $0.06–$0.09/Dth for baseload savings. Since both PECo BGS and competitive marketers lock in prices for a year or so, the price effect would be delayed by a year.

Since the lower winter prices in the mid-Atlantic would tend to discourage construction of new pipeline supply, the price benefit is likely to decline after several years. In addition, the addition of shale gas in the mid-Atlantic is likely to reduce the TETCo M-3 basis over time. It thus seems reasonable to reduce the price effects by 60% from 2019 through 2021. Table 3 summarizes these results for the midpoint of the DRIPE coefficients.

Table 3: Summary of Local Basis DRIPE, 2014$ Benefit per Dth Saved

	Space Heating			Base Load		
	PGW Transport	PECO Electricity	Total	PGW Transport	PECO Electricity	Total
2016	$0.011		$0.011	$0.005		$0.005
2017	$0.022	$0.156	$0.178	$0.010	$0.072	$0.083
2018	$0.033	$0.156	$0.189	$0.015	$0.072	$0.088
2019	$0.033	$0.156	$0.189	$0.015	$0.072	$0.088
2020	$0.023	$0.110	$0.132	$0.011	$0.051	$0.061
2021	$0.013	$0.063	$0.076	$0.006	$0.029	$0.035
2022+	$0.013	$0.063	$0.076	$0.006	$0.029	$0.035

Statewide Basis DRIPE

The values estimated above cover only the benefits to PGW transportation customers and to PECo electric customers. While I do not have winter transportation volumes for the other

Pennsylvania gas utilities, the collective gas consumption by eastern-Pennsylvania commercial and industrial customers (the classes most likely to be taking transportation service) is about 7.3 times that of PGW. I included in eastern Pennsylvania the service territories of PECo, GW, Pike County, UGI Penn Central and UGI Gas.[6]

Similarly, the electric utilities in the portion of Pennsylvania that is in MAAC, and hence primarily served by the gas plants east of the pipeline constraints includes PECo, PPL, Metropolitan Edison, Pike County, UGI and Pennsylvania Electric.[7] The sales of these utilities are about 2.5 times the sales of PECo alone.

Table 4 shows the effect of scaling the values in Table 3 by the eastern Pennsylvania total loads.

Table 4: Statewide Basis DRIPE, 2014$ Benefit per Dth Saved

	Space Heating			Base Load		
	LDC Transport	PA-MAAC Electricity	Total	LDC Transport	PA-MAAC Electricity	Total
2016	$0.080		$0.080	$0.037		$0.037
2017	$0.159	$0.391	$0.550	$0.074	$0.181	$0.255
2018	$0.239	$0.391	$0.630	$0.111	$0.181	$0.292
2019	$0.239	$0.391	$0.630	$0.111	$0.181	$0.292
2020	$0.167	$0.274	$0.441	$0.077	$0.127	$0.204
2021	$0.096	$0.156	$0.252	$0.044	$0.072	$0.117
2022+	$0.096	$0.156	$0.252	$0.044	$0.072	$0.117

Summary of Gas Price Effects

Each Dth of gas conservation would be expected to save PGW and PECo customers about $0.13 in reduced gas and electric prices due to wellhead gas prices, with up to $0.39 of additional savings from reduced basis for space-heating load reductions. Table 5 summarizes the results discussed above.

---

[6] Some of the UGI Central Penn Gas service territory is also to the east of the transportation constraints.

[7] While all of PennElec is in MAAC, some parts would be served by generation located to the west of the gas transmission constraints. On the other hand, some of the coop territories, which I have not included, appear to be on the constrained east side. In addition, generators in MAAC can set the market price in western Pennsylvania and western generation can set prices in MAAC, so the east-west split for electric supply is not as clean as for gas supply.

Table 5: Summary of Local Price Effects per Dth of Savings (2014$)

Year starting	Wellhead Price Effect		Basis Effect for deliveries by				Total Effect	
			Space Heat		Baseload		Heating	Base
	PGW	PECo	PGW	PECo	PGW	PECo		
2016	$0.032	$0.051	$0.011		$0.005		$0.043	$0.056
2017	$0.032	$0.051	$0.022	$0.156	$0.010	$0.072	$0.210	$0.134
2018	$0.032	$0.051	$0.033	$0.156	$0.015	$0.072	$0.221	$0.139
2019	$0.032	$0.051	$0.033	$0.156	$0.015	$0.072	$0.221	$0.139
2020	$0.032	$0.051	$0.023	$0.110	$0.011	$0.051	$0.164	$0.112
2021	$0.032	$0.051	$0.013	$0.063	$0.006	$0.029	$0.108	$0.086
2022+	$0.032	$0.051	$0.013	$0.063	$0.006	$0.029	$0.108	$0.086

From the perspective of all Pennsylvania energy consumers (which would be a reasonable perspective for the Pennsylvania PUC), the price-suppression benefits would be much larger. Pennsylvania end-use consumers use about 600 million Dth (about eight times PGW's use) and electric customers use about 162 million MWh (four times PECo's). The benefit of wellhead gas price suppression for all Pennsylvania customers would be about $0.68/Dth of gas consumption, not counting the basis price effect, which varies by year (and by location).

Table 6: Summary of Statewide Price Effects per Dth of Savings (2014$)

Year starting	Wellhead Price Effect		Basis Effect for deliveries by				Total Effect	
			Space Heat		Baseload		Heating	Base
	LDC Transport	PA-MAAC Electric	LDC Transport	PA-MAAC Electric	LDC Transport	PA-MAAC Electric		
2016	$0.233	$0.200	$0.080		$0.037		$0.313	$0.237
2017	$0.233	$0.200	$0.159	$0.391	$0.074	$0.181	$0.783	$0.455
2018	$0.233	$0.200	$0.239	$0.391	$0.111	$0.181	$0.863	$0.492
2019	$0.233	$0.200	$0.239	$0.391	$0.111	$0.181	$0.863	$0.492
2020	$0.233	$0.200	$0.167	$0.274	$0.077	$0.127	$0.674	$0.404
2021	$0.233	$0.200	$0.096	$0.156	$0.044	$0.072	$0.485	$0.317
2022+	$0.233	$0.200	$0.096	$0.156	$0.044	$0.072	$0.485	$0.317

I recommend that PGW use the DRIPE values in Table 6.