STATE OF MARYLAND

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of the Application of	**)**	
Columbia Gas of Maryland for	**)**	**Case No. 9159**
Authority to Increase Rates and	**)**	
Charges	**)**	

DIRECT TESTIMONY OF

PAUL CHERNICK

ON BEHALF OF

THE MARYLAND OFFICE OF PEOPLE'S COUNSEL

Resource Insight, Inc.

JANUARY 6, 2009

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I. Identification and Qualifications

Q: State your name, occupation and business address.

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

Q: Summarize your professional education and experience.

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

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

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

Q: Have you testified previously in utility proceedings?

A: Yes. I have testified approximately one hundred and ninety times on utility issues before various regulatory, legislative, and judicial bodies, including the Arizona Commerce Commission, Connecticut Department of Public Utility Control, District of Columbia Public Service Commission, Florida Public Service Commission, Maryland Public Service Commission, Massachusetts Department of Public Utilities, Massachusetts Energy Facilities Siting Council, Michigan Public Service Commission, Minnesota Public Utilities Commission, Mississippi Public Service Commission, New Mexico Public Service Commission, New Orleans City Council, New York Public Service Commission, North Carolina Utilities Commission, Public Utilities Commission of Ohio, Pennsylvania Public Utilities Commission, Rhode Island Public Utilities Commission, South Carolina Public Service Commission, Texas Public Utilities Commission, Utah Public Service Commission, Vermont Public Service Board, Washington Utilities and Transportation Commission, West Virginia Public Service Commission, Federal Energy Regulatory Commission, and the Atomic Safety and Licensing Board of the U.S. Nuclear Regulatory Commission.

Q: Have you testified previously before the Maryland Public Service Commission?

A: Yes. I have testified in the following cases:

- Case No. 9036; BGE Gas Rate Case, on cost allocation and rate design;
- Case No. 8278, on the adequacy of Baltimore Gas & Electric's (BGE's) Integrated Resource Plan;

- Case No. 8241, Phase II; Review of BGE's Avoided Costs;
- Case No. 8473; Review of the Power Sales Agreement of BGE with AES Northside;
- Case No. 8487; BGE Electric Rate Case, on cost allocation and rate design;
- Case No. 8179; Approval of Amendment No. 2 to Potomac Edison Purchase Agreement with AES Warrior Run;
- Case No. 8697, BGE gas rate increase, on cost allocation and rate design;
- Case No. 8720, Washington Gas Light DSM, on avoided costs and least-cost planning;
- Case No. 8725, merger of BGE and Potomac Electric Power Company, on allocation of merger benefits and rate reductions;
- Case No. 8774; Allegheny Power-Duquesne merger;
- Case No. 8794 and 8804; BGE restructuring;
- Case No. 8795; Delmarva Power & Light restructuring;
- Case No. 8797; Potomac Edison restructuring.

I also participated in DSM collaboratives and consultations with the large electric utilities and with Washington Gas.

Q: On whose behalf are you testifying?

A: My testimony is sponsored by the Maryland Office of People's Counsel (OPC).

II. Introduction

Q: Please describe the purpose of your testimony.

A: This testimony addresses the reasonableness of Columbia Gas of Maryland's ("Columbia") Cost of Service Study and residential rate design.

Q: What issues does your testimony address?

A: I evaluate the following Company proposals:

- The classification and allocation factors in its Cost of Service Studies ("COS Studies");[1]
- The reliance on its COS studies as the basis for its class rate spread proposal;
- Changes to the rate design of Residential Schedule 1, in particular, the proposed 41% increase in the customer charge.

III. Evaluation of Columbia's Cost-of-Service Studies

Q: What is the purpose of the cost-allocation process?

A: The purpose of the cost-allocation process is the fair assignment of the utility's total revenue requirement to the various rate classes. A fundamental principle of the process is that allocation based on cost causation results in an equitable sharing of embedded costs.

Q: What role should the embedded COS Study play in revenue allocation?

A: Any embedded-cost-based COS Study is approximate and based on judgment. Therefore, it should serve only as a guide to revenue allocation by class.

Q: Should the COS Study be the basis of rate design as well as revenue allocation by class?

A: No. Considerations of marginal cost and incentive effects, not embedded cost, should be the primary basis for design of rates for individual classes.

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[1] The COS Studies comprise a Demand/Commodity study and a Customer/Demand study, which vary only in their treatment of mains. Most of my review is relevant to both studies; my critique of the mains allocation is specific to the Customer/Demand study.

Q: Please briefly summarize Columbia's analysis.

A: Columbia has performed two cost-of-service studies. The two studies differ methodologically in only one respect: the treatment of main investment. The Demand/Commodity study classifies 50% of mains as demand-related and 50% as commodity-related. The Customer/Demand study classifies 33.85% of mains as demand-related and 66.15% as customer-related.

The Company performed two allocation studies to

> provide the outside limits of the possible allocations of mains to the various classes of service.... Columbia recognizes that no one cost of service study is the "right" study and the results of two such studies are useful in providing a useful range of returns for use as a guide in establishing appropriate rates. (Humrichouse prefiled, pp. 9–10)

Q: What were the results of these two studies?

A: The results of the two studies are quite different. According to the Demand/Commodity study, the residential class earns 99% of the Company average rate of return of 8.7%. However, under the Customer/Demand study, the residential class earns only 49% while the other three rate classes earn between 77% and 576% of the Company average ROR (Exhs. 11a and 11b).

The Company proposes to allocate the revenue increase based on some vaguely described "consideration" of the two cost studies (Schuster Direct, p. 6).

Q: Is the average of the results of these two studies more reliable than a single study?

A: No. In some situations, averaging the results of multiple COS studies can be useful in reducing reliance on uncertain allocation methods. In this case, the returns from the Company's two studies do not bracket the range of reasonable class revenue allocations. The Company's studies share flaws that overstate the cost of serving small customers, as I explain below.

Q: What problems have you identified with the Company's classification and allocation factors?

A: Both of Columbia's studies are flawed in that they

- allocate 99% of the services to residential and commercial customers (no matter how large) on simple unweighted customer number, ignoring the effect of size of customer;
- overlook the sharing of service drops by residential customers in multi-family dwellings;
- fail to reflect the variation in Customer Accounts, Customer Service & Information, and Sales Expenses with the size and type of the customer by allocating these costs on customer number;
- fail to reflect the broad function that these Administrative & General expenses serve by allocating these costs on non-fuel O&M.

In addition, while the allocation of mains in the Demand/Commodity study is reasonable, the Customer/Demand study approach is seriously flawed in the following respects:

- It overstates the customer-related portion of mains in the Customer/Demand study by misapplying the "Minimum Distribution System" method;
- It misallocates the portion of mains classified as demand-related by ignoring the load-carrying capability of the customer-related portion.

Q: What would be the effect of your recommendations on the overall allocation of costs?

A: The changes I recommend would generally reduce the allocation of costs to the residential class and increase the allocation to the commercial and industrial customers.

A. Classification and Allocation of Mains in the Customer/Demand Study

Q: What is Columbia's approach to classifying mains plant in the Customer/Demand Study?

A: Columbia uses a minimum-system analysis, which conceptualizes the division between load- and customer-number-related plant as a simple rule:

- the number of units (feet of main) is due to the number of customers,
- the sizing of equipment above some "minimum size" is due to the load.

This analysis estimates the cost of a hypothetical distribution system in which each foot of main is the minimum-size pipe. The analysis asks: How much would it have cost to install the same number of units (i.e., the same feet of mains), but with the size of the pipe limited to the current minimum unit normally installed?

This approach assumes that every foot of main was installed to extend gas service into new geographical areas purely to connect new customers to the distribution system, without consideration of peak load or annual throughput.

Q: How did Columbia determine the customer-related portion of main investment?

A: Columbia identified 2″ pipe as the minimum-sized main and calculated the cost of the minimum system as the product of (1) the total feet of main and (2) the average book cost of 2″ pipe. The Company then computed the ratio of this estimated minimum-system cost to the actual system cost and assumed that ratio equaled the portion of main investment that is customer-related.

The Company's "customer component factor" equals the ratio of the average book cost of 2″ pipe, $9.69 per foot, to the overall average cost of mains ($49,272,087 ÷ 3,362,869 = $14.65), or 0.6615 (Attachment KLH-2, p. 2).

Q: What is the basis for Columbia's assumption that 2″ is the minimum pipe size?

A: Columbia identifies 2″ pipe as the "most common, minimum size" (Attachment KLH-2, p. 2). It is not the minimum size in service.

Q: What problems have you identified with the Customer/Demand mains allocator?

A: The Customer/Demand mains allocator has at least the following problems:

- The minimum-system method is conceptually flawed, in that neither the mileage of mains nor the cost of those mains is directly related to the number of customers.
- The Company's classification method improperly uses cost comparisons based on mixed current dollars.
- The Customer/Demand method allocates too much demand-related plant to small customers because it ignores the load-carrying capability of the minimum-sized system.

1. Conceptual Errors in the Minimum-Distribution-System Approach

Q: What are the conceptual flaws of the minimum-system approach?

A: The minimum-system computation ignores the following aspects of distribution planning and investment.

- Much of the cost of a distribution system is required to cover an area, and is not really sensitive to either load or customer number. For example, extending a main to reach many customers in one multi-family building is no more expensive than serving one commercial customer of the same size. The distribution cost of serving a geographical area for a given load is roughly the same whether that load is from concentrated commercial or dispersed residential customers.

- Load drives footage of mains, as well as the diameter of the pipe.
- Revenues drive the Company's decision to extend mains and the share of distribution system extensions recovered through rates.
- System pressure may also be increased to carry more load, increasing distribution plant and O&M costs.

Q: Does the literature support the view that the length of mains is not determined by the number of customers?

A: Yes. As Bonbright, Danielsen & Kamerschen (p. 491) explain, the minimum-system approach attempts to classify costs that are fundamentally "unassignable:"

> The inclusion of the costs of a minimum-sized distribution system among the customer-related costs seems to us clearly indefensible…. [Cost analysts are] under impelling pressure to fudge their cost apportionments by using the category of customer costs as a dumping ground.[2]

Small customers are especially burdened when a high percentage of costs that are essentially unallocable are assumed to be customer-related.

Q: How can load affect the footage of main installed?

A: As the Company itself explains, there are a number of situations in which additional feet of mains are installed to meet increased loads (OPC V-39) by

- replacing the line with larger diameter pipe;
- paralleling the existing system with an additional main;
- adding (1) an additional source of supply from a new point of delivery from an upstream pipeline, (2) a district regulator from a higher-pressure

[2]Bonbright, James C., Albert L. Danielsen, and David R. Kamerschen. 1988. *Principles of Public Utility Rates* 2nd Ed. Arlington, Va.: Public Utilities Reports.

portion of the distribution system; or (3) an additional section of main to loop the system and connect what would otherwise be dead-end systems;

- replacing bare steel or cast iron mains sections to allow increases in system pressure.

Even if the installation of an additional main happens to be triggered by the addition of a new customer, so long as the investment would not be required if the loads of new and/or existing customers were lower, that new main would be 100% demand-related.

Q: Other than length and diameter of mains, are other costs of mains driven by demand?

A: Yes. As Columbia describes in OPC V-39, increasing system pressure will usually require a formal uprate procedure as described in CFR 49 Part 192 Subpart K—Uprating. The greater pressure will likely impose additional investment and operating costs.

Q: How does customer revenue influence the Company's investment in mains?

A: The Company will extend mains at its expense only to the extent that it expects that the additional revenues justify the expenditure; any additional cost is billed directly to the customer requiring the extension (OPC V-26). Hence, anticipated revenues affect both whether the main is built and, if it is built, what portion of the investment ends up in rate base.

The costs of mains in rates are thus driven, in part, by revenues, rather than customer number.

Q: Ideally, how would the minimum-system analysis of mains reflect the customer, load, and revenue-related components?

A: The appropriate classification process would consist of the following four steps:

1. Identifying the feet and cost of main that should be considered load-related due to load-related replacement, looping, supply enhancement, or pressure increase.
2. Identifying the feet and cost of main that should be considered revenue-related line extensions.
3. Computing the cost of covering the remainder of the system with minimum-size pipe (which would be classified as customer-related).
4. Subtracting the results of steps 1–3 above from total investment, to determine the costs related to demands related in excess of the capability of the minimum pipe.

Q: Have you applied this approach to Columbia's mains investment?

A: No. I do not have enough information about the history and justifications of the Company's mains investments to identify the load- and revenue-related costs. I recommend that the Commission require Columbia to incorporate the considerations I described above in future minimum-system analyses. Until Columbia corrects its minimum-system calculation, the Commission should give little weight to the Customer/Demand study.

2. Allocation of Demand-Related Mains Investment

Q: How does Columbia allocate the cost of mains, above the estimated cost of the minimum system?

A: Columbia allocates that additional mains cost in proportion to class design-day load.

Q: Is that an appropriate allocator for that cost component?

A: No. The "demand-related" portion of mains investment is actually an estimate of the investment *in excess* of the same network composed entirely of 2″ pipe. Hence, the cost should be allocated in proportion to the class loads *in excess* of the load-serving capability of a 2″ system.

Q: Is the distinction between total demand and excess demand important in this case?

A: Yes. Columbia's minimum system of 2″ pipe is sufficient to carry a large portion of load for small customers, depending on the number of residential customers served on a single main and the pressure of the mains. For most residential customers, the minimum system probably carries all the load they need.

Q: How should Columbia's error in computing excess demand be corrected?

A: To remove the double-counting, the demand-related component of plant should be allocated according to excess load (that is, net of the load carried by the minimum system). For residential customers, that excess is usually zero. Therefore, the residential class should not be allocated any of the demand-related cost.

Q: How would allocating the excess mains cost only on excess load affect the allocation to the residential class?

A: In its Customer/Demand study, Columbia allocates 75% of mains costs to residential customers, as shown in Attachment KLH-2. Allocating to the residential class only Columbia's estimate of the minimum system reduces the residential share of mains costs to 58.53%.

Q: Can Columbia apply this method to other classes?

A: Yes. The excess load by class depends on the distribution of customers along mains and the pressure (and hence the load-serving capability) of each section of line. Columbia could perform a detailed analysis of excess demand by class, which would be a test of my estimate that the residential excess load is zero.

3. Minimum Distribution Calculation in Constant Dollars

Q: Why is it improper to use cost comparisons based on mixed current dollars?

A: Since it is computed from book-cost data in mixed-years dollars, Columbia's estimate of the ratio of the minimum system to the actual system cost (and therefore the percentage of plant classified as customer-related) is affected not only by the greater costs of the larger pipes but also by their relative ages. The portion of costs that is associated with the minimum-sized system should not be affected by the year in which pipe is installed or replaced.

The customer-related portion must be compared to the cost of the entire account (in the same year's dollars). Translating actual mixed dollars into constant dollars can be difficult, especially under conditions of technical change and different inflation rates for large and small installations (small installations are often more related to labor costs than are large ones, for example).

Q: What effect does restating the book costs in constant dollars have on the Company's minimum distribution calculation?

A: This correction reduces the minimum-system portion of the mains from Columbia's estimate of 66.1% to 61.6%.

Q: How does that change in the cost of the minimum system affect the allocation of mains costs to residential customers?

A: Reducing the minimum system to 61.6% of mains cost reduces the residential allocation for mains from 58.53% to 54.55%.[3]

B. Classification and Allocation of Services

Q: How does Columbia classify and allocate services?

A: The Company treats services as 100% customer-related, but recognizes that the size and cost of a service line depends on current and anticipated load (Policy/Procedure Reference 530-2, p. 2).

Columbia allocated Services in the following four steps.[4]

1. groups service lines into two pipe size categories, less-than-3″ and 3″-and-larger, using data from the Plant Accounting Records;
2. determines the number of residential, commercial, and industrial customers in each rate class. The residential rate class includes all residential customers (and no others);
3. assigns the 3″-and-larger services to the industrial customers, and allocates the cost in proportion to the industrial customers in each rate class;
4. allocates the cost of the other group of services in proportion to the number of non-industrial (residential and commercial) customers in each rate class.

Q: Does the assignment of the larger services to the industrial customers have much of an effect on the allocation to residential customers?

A: No. Since 98.6% of the total book cost of services is in the less-than-3″ pipe size category and 99.9% of customers are non-industrial (Attachment KLH-1, p. 5),

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[3]With Columbia's misapplication of the minimum-system method, putting costs in constant dollars reduces the residential share of the mains allocation from 75% to 73.2%.

[4]The Company summarizes this derivation in Attachment KLH-1, p. 5, and as shown in the spreadsheet Exhibit 11a (Allocated Cost of Service—Demand/Commodity), Tab "Allocations."

separating out the 3″-and-larger services does not have much of an effect. For the residential class, the Services allocator (Factor 15), which is 87.4%, differs little from the customer number allocator (Factor 6), which is 88.5% (Exhibit 11a, pp. 12–13).

1. *Cost of Service Line by Customer Type*

Q: What is the embedded cost of a service per customer according to the Company's Cost of Service Study?

A: The following table provides a comparison of Columbia's assumed unit cost by customer type:[5]

Table 1: Columbia Allocation of Service Costs

Class		Customer Number	Cost per customer	Total Cost
Residential		28,629	$910	$26,043,895
GS	C	3,594	910	3,269,474
	I	6	4,857	29,140
IS	C	26	910	23,652
	I	1	4,857	4,857
TS	C	16	910	14,555
	I	77	4,857	373,958
Total		32,349		$29,759,530

According to the Company's analysis, the commercial customers, no matter how large they are, require no larger or more expensive a service than do residential customers.

Q: Has the Company adequately demonstrated that residential and commercial services have the same average cost?

[5] These service costs reflect only Plant Accounting Record data, not the higher plant in Account 380–Services. Columbia uses the class ratios of these plant costs to allocate all service costs.

A: No. The relationship is merely an assumption made by the Company, not a result of data or analysis.

Q: Does the Company's use of its Plant Accounting Records support this crucial assumption?

A: No, for the following reasons.

- The Plant Accounting Records cannot be the basis of a direct assignment simply because they do not record services by customer type or rate class;

The less-than-3″ category of services assigned to all non-industrial customers alike actually contains a wide range of pipe sizes, that is, ½″, ¾″, 1″, 1¼″, 1½″, 2″, and 2½″ (Attachment OPC V-19). Typical pipe size could vary between commercial and residential customers. Unfortunately, the Company never tracked which class each service line was installed for and after 1973 stopped differentiating the number and cost of installations by pipe size for lines smaller than 3″ (Attachment OPC V-19).[6]

- A simple breakdown of services by size of pipe ignores other service line characteristics that affect cost;
- The Plant Accounting Records provide costs in mixed years' dollars, ranging from 1907 to 2008. The data should be adjusted to same year's dollars to remove the effect of vintage on the relationship between the pipe size and the cost of a service.
- The Plant Accounting Records and the Company ignore the sharing of services by residential customers in multi-family buildings.

Q: What other factors can affect the cost of a service?

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[6]According to OPC V-22, the Plant Accounting Records should contain separate data by size of service until sometime in the 1990s.

A: Several interlinked factors determine the cost of service line, particular the following:[7]

- pipe size,
- length of service line,
- minimum pressure of system.

Cost and customer size may increase with these three factors. As the Company explains in its response to OPC V-30 (in the case of mains):

> These unknowns are critical because gas pressure in a main drops due to friction created by flow, and the volume of throughput in a given length of pipe is a direct function of the operating pressure (because gas is compressible), increasing the pressure allows greater volume in the same space.

Q: Is the residential service likely to be less costly than the average commercial service?

A: Yes, for the following reasons:

- Residential customers are, on average, much smaller users than commercial customers,
- The load-carrying capability of services varies considerably with pipe size,
- The cost of a service tends to increase with pipe size.

Q: How much do the peak loads of residential and commercial customers differ?

A: Substantially. Commercial GS customers have on average almost 6 times the design peak load of the typical residential customer; Commercial IS and TS customers have 19 and 64 times the design peak of RS customers, respectively.[8]

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[7]Policy/Procedure Reference No. 530-10, Exhibit A, provided in OPC V-09 Attachment A

[8]Customer number and design day by customer group and rate class is provided in Company's Exhibit 11a Excel file, Tab "Allocations."

Q: How does load-carrying capability vary with pipe size in the less-than-3″ group?

A: The 2″ service carries 2.5 to 3 times the load of a 1¼″ IPS (iron pipe size) service and 7 to 9 times the load of a 1″ CTS (copper tube size) service, all other conditions equal.[9] (Policy/Procedure Reference No. 530-10, Exhibit A, provided in OPC V-09, Attachment A).

Q: What do Company policies and guidelines tell you about the size of pipe typically installed in residential services?

A: It appears that the Company typically installs 1″ or 1¼″ pipe for residential customers. In fact, Columbia's distribution planning guidelines direct that "1¼″ IPS [iron pipe size] or larger size service lines are to be installed *only when a smaller service line cannot supply the load*" (Policy/Procedure Reference No. 530-10, p. 2; emphasis added). According to the Company's own design guidelines, 1″ pipe is more than adequate to supply the load of a residential heating customer:

- For use in system design, the Company estimates that the single residential heating customer has a peak hour load of between 67 and 100 cubic feet per hour (cfh). The high end of the range reflects the lowest-efficiency customer considered, a 2,000 ft^2 old-style home with a 65% efficiency furnace and R-6 insulation. (Policy/Procedure Reference No. 530-2, provided in response to OPC V-09).
- According to the service line sizing tables, the least-capacity 50-foot service on a low pressure system—a plastic 1″ CTS pipe—will carry 170 cfh, a 100-foot plastic 1¼″ IPS pipe will carry 340 cfh, and a 300-foot

[9]The load carrying capability of the pipe depends on length, pressure and type as well as pipe size.

plastic 1¼″ IPS pipe (the longest in the sizing table) will carry 200 cfh. In no case in these sizing tables would a 2″ service line be needed to meet a typical residential heating customer's load (Policy/Procedure Reference No. 530-10, Exhibits A through E).

The Company acknowledges that the residential services are at the low end of the less-than-3″ category:

> The typical size of a residential service operating at low pressure is 1.25 inches in diameter. The typical size of residential services operating at elevated pressure has historically been .50 inches in diameter. That design standard was changed several years ago to 1.0 inches to recognize a number of requests we were receiving for increased capacity to accommodate pool heaters and other additional loads, after the services were installed. (OPC VIII-4)

Q: Is the Company's treatment of mains and services internally consistent?

A: No. Columbia's approaches to classifying mains and allocating services are incompatible. The Company considers 2″ as the appropriate minimum size for a main that serves the combined load of *many* residential customers (OPC V-31; VIII-3). Yet, to develop the cost of a service line that serves only a *single* residential customer, the Company includes installations that have 2″ or 2½″ pipe.

Q: By assigning unrealistically large services to the residential class, is it likely that the Cost of Service Study has over-allocated services costs to the residential class?

A: Yes.

Q: Have you analyzed the Continuing Property Record for evidence of the effect of size on cost within the less-than-3″ group?

A: Yes. The records do contain a limited amount of cost data by size within the less-than-3″ (Attachment OPC V-19). If anything, the Continuing Property

Record indicates that, within the less-than-3″ group, the unit cost of the smaller services is much lower than the average.

Q: Please describe your unit-cost comparison.

A: I separated out the effect of vintage on cost by translating book costs in mixed dollars into same year's dollars, calculated the unit-cost by pipe size, and compared across pipe size groups.

Q: What do your comparisons suggest about the relationship between pipe size and the cost of the service?

A: The available data indicate that the 1″ and 1¼″ services may be half the cost of the larger 2″ services.[10]

Q: How could this cost differential be incorporated into the calculation of the Services allocator?

A: To reflect a two-to-one cost differential between commercial and residential services only one change in the calculation (in Attachment O.1 to OPC V-02) is required: instead of a unit cost of $910 for all of the less-than-3″ services, I used $818 for the residential services in that category and twice that, or $1,636 for commercial services.[11] This change alone reduces the residential services allocator from 88% to 79%.

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[10]Detailed comparisons of service costs are complicated, because Columbia's data do not include the length of the services, and include three classes of services: main to curb, curb to meter, and main to meter. To make matters worse, Columbia reports show about 70% more services from main to curb than from curb to meter; that differential may represent record-keeping errors, older abandoned services, services installed in anticipation of customers who never connected, customer-owned services, or something else (Attachment OPC V-19).

[11]These unit costs are calculated such that the weighted average unit cost, weighted by residential and commercial customer number, remains $910.

Table 2: Service Allocator Corrected for Cost per Service

		Columbia Proposal			Commercial Services Twice Cost of Residential		
Class	**Customer Number**	*Cost per customer*	*Total*	*Allocator*	*Cost per customer*	*Total*	*Allocator*
Res.	28,629	$910	26,043,895	87.51%	$818	23,406,208	78.65%
GS C	3,594	910	3,269,474	10.99%	1,635	5,876,692	19.75%
I	6	4,857	29,140	0.10%	4,857	29,140	0.10%
IS C	26	910	23,652	0.08%	1,635	42,514	0.14%
I	1	4,857	4,857	0.02%	4,857	4,857	0.02%
TS C	16	910	14,555	0.05%	1,635	26,162	0.09%
I	77	4,857	373,958	1.26%	4,857	373,958	1.26%
Total	32,349		29,759,530	100.00%		29,759,530	100.00%

Q: Have you identified any other flaws in Columbia's proposed allocation of services?

A: Yes. It ignores the sharing of services by customers in multi-family buildings (OPC V-24). The Company has not estimated the number of shared services or portion of its residential customers that are in multi-family buildings or the number of service installed (OPC V-23).

Q: Have you estimated what the impact of shared services would be on the residential services allocator?

A: Yes. While Columbia does not provide data on the mix of housing types and the number of customers per service in its Maryland jurisdiction (OPC V-11 and 23), the U.S. Census Bureau's 2005–2007 American Community Survey of housing characteristics indicates that about 20% of housing in Garrett, Allegany, and Washington counties is multi-family. According to this census information, 13.3% of the customers are in multi-family housing with two to nine units, and 6.6% in multi-family housing with more than nine units.

Table 3: Residential Service Number, with Shared Services

	Units	Share	Units per Service	Number of Services	
1-unit, detached	71,698	68.2%	1	71,698	
1-unit, attached	12,477	11.9%	1.5	8,318	
2 units	4,414	4.2%	2	2,207	
3 or 4 units	4,196	4.0%	3.5	1,199	
5 to 9 units	5,370	5.1%	7	767	
10 to 19 units	3,357	3.2%	14.5	232	
20 or more units	3,556	3.4%	20	178	
Total housing units	105,068	100.0%		84,598	81%
Units in multi-family housing	20,893	19.9%			

Source: U.S. Census Bureau

Depending on the number of units in each category sharing services and assuming that the counties' housing mix is a good proxy for Columbia's customer mix, the total number of services to residential customers may well be 20% less than Columbia assumes for allocation purposes, as shown in the table above.

Q: Would similar adjustments apply to other classes?

A: No. Other than multi-family residential customers on the residential rate, relatively few customers are likely to share services.[12]

Q: What effect would the sharing of services have on the services allocator?

A: Combining the shared-services correction with the service-size correction could reduce the residential allocation of service costs from 88% to less than 75%.

[12]In some cases, small commercial customers in a strip mall or office building will share a service.

C. Allocation of Customer Accounts, Customer Service & Information, and Sales Expenses

Q: How does Columbia classify and allocate Customer Accounts, Customer Service & Information, and Sales expenses?

A: Columbia classifies these costs as customer-related and allocates them according to customer number.

Q: Is this approach reasonable?

A: No. These expenses are likely to vary with the size of the customer or its revenues.

Q: Please explain why.

A: In general, larger customers should be expected to have more complicated installations, metering, and billing, and to warrant more time and attention from Columbia. It is difficult to believe that Columbia spends as much time and attention on each residential customer as on each large commercial or industrial customer, considering the vast differences in customer size and complexity. For example, the average TS customer's bill is more than 100 times the average residential bill.

Q: Has Columbia provided adequate justification for assuming that the size of customer has no influence on customer costs?

A: No. The Company has provided no support for its assumption (OPC VIII-15). It did not consider, for example, the costs of dispatch of interruptible loads or the more complex record keeping required for the schedule IS customer, because "these costs are not classified to a specific account or accounts" (OPC VIII-16(b) & (c)). Instead, the Company simply states that, because these Customer Accounts, Customer Service & Information, and Sales expenses "are directly related to number of customers" and "directly support customers," they should be allocated based on customer number (Attachment KLH-3, p. 9).

Q: What changes do you recommend to the allocation of these expenses?

A: The Company should develop weighted customer-number allocators that reflect the effect of size and type of customer on these expenses.

D. Allocation of Administrative and General Expenses

Q: How does Columbia allocate Administrative and General expenses?

A: It allocates these costs based solely on O&M excluding purchased gas cost.

Q: What is the Company's justification for this allocation method?

A: In the Company's view, non-gas O&M is an appropriate allocator because A&G expenses are "overheads to the entire Company operation and, therefore, follow the allocation of the aggregate of all other previously allocated [non-fuel] O&M costs" (Attachment KLH-3, p. 9).

Q: Is this allocator appropriate?

A: No. A&G expenses support all aspects of utility operation, investment, and planning. They are general costs which are driven by all utility system costs, including plant and purchased gas, not just non-gas O&M. A substantial portion of A&G consists of such expenses as the following:

- salaries of executives, officers and other employees concerned with broad oversight of the utility's business, and associated supplies and expenses (Accounts 920 and 921);
- regulatory expenses;
- industry association dues, other experimental and general research expenses, and costs of publishing information and reports to stockholders.

Q: How should Administration and General expenses be allocated?

A: Most of A&G should be assigned to rate classes based on a broad allocator, such as revenues.[13] Revenue is a better composite allocator than non-gas O&M because it reflects the overall allocation of all costs.

IV. Proposed Class Revenue Allocation

Q: Please describe briefly Columbia's revenue allocation proposal.

A: Columbia proposes a disproportionate increase in residential base revenues, 36% above the increase in total Company base revenues (Exhibit 2-E).

Q: Did the Company rely on the COS studies in proposing this revenue spread?

A: Yes. Ms. Schuster proposes a large increase in the residential rate based on a perception that the class is under-earning.

Q: Do the Company's cost-of-service studies support disproportionate increases to the residential class?

A: No. The Company's own Demand/Commodity Study indicates that the residential class is earning the Company average rate of return. The Customer/Demand study when corrected for just some of its errors has similar results.

Q: If the Commission grants the Company a rate increase in this proceeding, how should the rate increase to residential rates be determined?

A: The residential base revenues should be increased by the overall average increase allowed.

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[13] Administrative and General Account 926, Employee Pensions and Benefits, is clearly labor-related and therefore properly allocated according to non-fuel O&M, as the Company has done.

Q: If the Commission orders a reduction in Columbia's rates in this proceeding, how should residential base rates change?

A: In that case, residential base rates should decline by the same percentage as the average company-wide rate reduction.

V. Residential Rate Design

A. Customer Charge Increase

Q: What is the Company's basis for increasing the residential customer charge by 41%, from $9.25 to $13 per month?

A: The Company derives a target residential customer charge of $22.83 (Company Exhibit 11c). It is intended to recover all residential costs classified as customer-related in the Customer/Demand COS Study, including services and customer-related mains investment.

Q: Should the results of the Customer/Demand Study be the basis for the proposed increases to the residential customer charges?

A: No, for the following reasons:

- The Study overstates customer-related costs,
- The Study over-allocates costs to the residential class.
- The large increase in the customer charge disproportionately affects small customers' bills.

Q: What costs are appropriately recovered through a customer charge?

A: The customer charge should be limited to those costs that are independent of the size of the customer. Only the costs of serving the smallest customers should be in the customer charge. Otherwise, small customers would subsidize large customers. Costs that vary with usage should be recovered through the commodity charge.

Q: What costs other than mains should be excluded from the calculation of the residential customer charge?

A: The smallest residential customers are likely to live in multi-family housing. Those smaller customers would likely share a service with other customers in an apartment building. The cost of the service varies with the load of the building, not with the number of customers, and therefore does not belong in the customer charge.

The Company's calculation includes other costs that vary with the size and type of customer:

- Meter reading costs. In an apartment building, a single meter in a bank of meters is likely to require much less meter reading time than a single family home.
- Customer Accounts and Customer Service & Information expenses (as explained above).

Q: What would the customer charge be if it reflected only the costs of minimum-size residential customers in multi-family housing?

A: I estimated the customer costs for customers living in multi-family dwellings by removing the return, depreciation, and O&M expenses associated with mains and services from the Company's calculation.. The result is a customer charge of less than $5 per month.

VI. Summary and Recommendations

Q: Please summarize your recommendations.

A: On the cost-of-service study, I recommend in Section III the following improvements in classifications and allocations:

- Revision of the Services allocator, based on a more detailed analysis of the relationship between cost and size of service line;
- Rejection of the Company's Customer/Demand Study, or substitution of an improved classification and allocation methodology for mains to reflect the effect of load and customer revenue on line extensions;
- Reallocation of Customer Accounts, Customer Service & Information, and Sales Expenses to reflect the variation in cost with the size and type of the customer;
- Reallocation of Administrative & General expenses to reflect the broad function that these costs serve.

In setting the revenue allocation, the Commission should recognize that the deficiencies in the COS allocations bias the COS results, in particular tend to overstate the costs of serving the residential class. For reasons stated above, Columbia has allocated an excessive share of costs to the residential class. Since the COS Study is flawed in a number of areas, it should not be relied on for determining revenue allocation until these problems are corrected.

In residential rate design, the Commission should reject Columbia's proposed customer charge increase, and collect any increase in allowed revenues through the commodity charges, especially in the winter tail block. If the Commission orders a reduction in Columbia's rates, the residential customer charge should be reduced.

Q: Does this conclude your testimony?

A: Yes.

Exhibit PLC-1

PAUL L. CHERNICK

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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

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

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

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

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

4. **MDPU** 19494; Phase II; Boston Edison Company Construction Program; Massachusetts Attorney General; April 1 1979.

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

11. **MEFSC** 79-33; Eastern Utilities Associates 1979 Forecast; Massachusetts Attorney General; July 16 1980.

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

12. **MDPU** 243; Eastern Edison Company Rate Case; Massachusetts Attorney General; August 19 1980.

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

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

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

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

    Cost comparison methodology; nuclear cost estimates; cost of conservation, co-generation, and solar.

15. **MDPU** 472; Recovery of Residential Conservation Service Expenses; Massachusetts Attorney General; December 12 1980.

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

16. **MDPU** 535; Regulations to Carry Out Section 210 of PURPA; Massachusetts Attorney General; January 26 1981 and February 13 1981.

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

17. **MEFSC** 80-17; Northeast Utilities 1980 Forecast; Massachusetts Attorney General; March 12 1981 (not presented).

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

18. **MDPU** 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. **MDPU** 1048; Boston Edison Plant Performance Standards; Massachusetts Attorney General; May 7 1982.

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

20. **DCPSC** FC785; Potomac Electric Power Rate Case; DC People's Counsel; July 29 1982.

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

21. **NHPUC** DE1-312; Public Service of New Hampshire-Supply and Demand; Conservation Law Foundation, et al.; October 8 1982.

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

22. **Massachusetts 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. **Illinois Commerce Commission** 82-0026; Commonwealth Edison Rate Case; Illinois Attorney General; October 15 1982.

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

24. **New Mexico PSC** 1794; Public Service of New Mexico Application for Certification; New Mexico Attorney General; May 10 1983.

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

25. **Connecticut Public Utility Control Authority** 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. **MDPU** 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. **Massachusetts 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. **Connecticut Public Utility Control Authority** 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. **MEFSC** 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. **Michigan 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. **MDPU** 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. **MDPU** 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. **Michigan 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. **MDPU** 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. **Pennsylvania 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. **NHPUC** 84-200; Seabrook Unit 1 Investigation; New Hampshire Public Advocate; November 15 1984.

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

39. **Massachusetts Division of Insurance;** Hearing to Fix and Establish 1985 Automobile Insurance Rates; Massachusetts Attorney General; November 1984.

    Profit margin calculations, including methodology and implementation.

40. **MDPU** 84-152; Seabrook Unit 1 Investigation; Massachusetts Attorney General; December 12 1984.

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

41. **Maine PUC** 84-120; Central Maine Power Rate Case; Maine PUC Staff; December 11 1984.

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

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

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

43. **MDPU** 1627; Massachusetts Municipal Wholesale Electric Company Financing Case; Massachusetts Executive Office of Energy Resources; January 14 1985.

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

44. **Vermont PSB** 4936; Millstone 3; Costs and In-Service Date; Vermont Department of Public Service; January 21 1985.

    Construction schedule and cost of completing Millstone Unit 3.

45. **MDPU** 84-276; Rules Governing Rates for Utility Purchases of Power from Qualifying Facilities; Massachusetts Attorney General; March 25 1985, and October 18 1985.

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

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

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

47. **Massachusetts 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. **New Mexico PSC** 1833, Phase II; El Paso Electric Rate Case; New Mexico Attorney General; December 23 1985.

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

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

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

50. **MDPU** 85-270; Western Massachusetts Electric Rate Case; Massachusetts Attorney General; March 19 1986.

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

51. **Pennsylvania PUC** R-850290; Philadelphia Electric Auxiliary Service Rates; Albert Einstein Medical Center, University of Pennsylvania and AMTRAK; March 24 1986.

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

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

    Recommendations for Power Plant Performance Standards for Palo Verde nuclear units 1, 2, and 3.

53. **Illinois Commerce Commission** 86-0325; Iowa-Illinois Gas and Electric Co. Rate Investigation; Illinois Office of Public Counsel; August 13 1986.

    Determination of excess capacity based on reliability and economic concerns. Identification of specific units associated with excess capacity. Required reserve margins.

54. **New Mexico PSC** 2009; El Paso Electric Rate Moderation Program; New Mexico Attorney General; August 18 1986. (Not presented).

    Prudence of EPE in generation planning related to Palo Verde nuclear construction, including failure to reduce ownership share and failure to pursue alternatives. Review of industry literature, cost and schedule histories, and retrospective cost-benefit analyses.

    Recommendation for rate-base treatment; proposal of power plant performance standards.

55. **City of Boston, Public Improvements Commission;** Transfer of Boston Edison District Heating Steam System to Boston Thermal Corporation; Boston Housing Authority; December 18 1986.

History and economics of steam system; possible motives of Boston Edison in seeking sale; problems facing Boston Thermal; information and assurances required prior to Commission approval of transfer.

56. **Massachusetts 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. **MDPU** 87-19; Petition for Adjudication of Development Facilitation Program; Hull (MA) Municipal Light Plant; January 21 1987.

    Estimation of potential load growth; cost of generation, transmission, and distribution additions. Determination of hook-up charges. Development of residential load estimation procedure reflecting appliance ownership, dwelling size.

58. **New Mexico PSC** 2004; Public Service of New Mexico Nuclear Decommissioning Fund; New Mexico Attorney General; February 19 1987.

    Decommissioning cost and likely operating life of nuclear plants. Review of utility funding proposal. Development of alternative proposal. Ratemaking treatment.

59. **MDPU** 86-280; Western Massachusetts Electric Rate Case; Massachusetts Energy Office; March 9 1987.

    Marginal cost rate design issues. Superiority of long-run marginal cost over short-run marginal cost as basis for rate design. Relationship of consumer reaction, utility planning process, and regulatory structure to rate design approach. Implementation of short-run and long-run rate designs. Demand versus energy charges, economic development rates, spot pricing.

60. **Massachusetts Division of Insurance** 87-9; 1987 Workers' Compensation Rate Filing; State Rating Bureau; May 1987.

    Profit margin calculations, including methodology, implementation, surplus requirements, investment income, and effects of 1986 Tax Reform Act.

61. **Texas PUC** 6184; Economic Viability of South Texas Nuclear Plant #2; Committee for Consumer Rate Relief; August 17 1987.

    STNP operating parameter projections; capacity factor, O&M, capital additions, decommissioning, useful life. STNP 2 cost and schedule projections. Potential for conservation.

62. **Minnesota PUC** ER-015/GR-87-223; Minnesota Power Rate Case; Minnesota Department of Public Service; August 17 1987.

Excess capacity on MP system; historical, current, and projected. Review of MP planning prudence prior to and during excess; efforts to sell capacity. Cost of excess capacity. Recommendations for ratemaking treatment.

63. **Massachusetts Division of Insurance** 87-27; 1988 Automobile Insurance Rates; Massachusetts Attorney General and State Rating Bureau; September 2 1987. Rebuttal October 8 1987.

    Underwriting profit margins. Effect of 1986 Tax Reform Act. Biases in calculation of average margins.

64. **MDPU** 88-19; Power Sales Contract from Riverside Steam and Electric to Western Massachusetts Electric; Riverside Steam and Electric; November 4 1987.

    Comparison of risk from QF contract and utility avoided cost sources. Risk of oil dependence. Discounting cash flows to reflect risk.

65. **Massachusetts Division of Insurance** 87-53; 1987 Workers' Compensation Rate Refiling; State Rating Bureau; December 14 1987.

    Profit margin calculations, including updating of data, compliance with Commissioner's order, treatment of surplus and risk, interest rate calculation, and investment tax rate calculation.

66. **Massachusetts Division of Insurance;** 1987 and 1988 Automobile Insurance Remand Rates; Massachusetts Attorney General and State Rating Bureau; February 5 1988.

    Underwriting profit margins. Provisions for income taxes on finance charges. Relationships between allowed and achieved margins, between statewide and nationwide data, and between profit allowances and cost projections.

67. **MDPU** 86-36; Investigation into the Pricing and Ratemaking Treatment to be Afforded New Electric Generating Facilities which are not Qualifying Facilities; Conservation Law Foundation; May 2 1988.

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

68. **MDPU** 88-123; Petition of Riverside Steam & Electric Company; Riverside Steam and Electric Company; May 18 1988, and November 8 1988.

    Estimation of avoided costs of Western Massachusetts Electric Company. Nuclear capacity factor projections and effects on avoided costs. Avoided cost of energy interchange and power plant life extensions. Differences between median and expected oil prices. Salvage value of cogeneration facility. Off-system energy purchase projections. Reconciliation of avoided cost projection.

69. **MDPU** 88-67; Boston Gas Company; Boston Housing Authority; June 17 1988.

Estimation of annual avoidable costs, 1988 to 2005, and levelized avoided costs. Determination of cost recovery and carrying costs for conservation investments. Standards for assessing conservation cost-effectiveness. Evaluation of cost-effectiveness of utility funding of proposed natural gas conservation measures.

70. **Rhode Island PUC** Docket 1900; Providence Water Supply Board Tariff Filing; Conservation Law Foundation, Audubon Society of Rhode Island, and League of Women Voters of Rhode Island; June 24 1988.

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

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

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

72. **Vermont PSB** 5270, Module 6; Investigation into Least-Cost Investments, Energy Efficiency, Conservation, and the Management of Demand for Energy; Conservation Law Foundation, Vermont Natural Resources Council, and Vermont Public Interest Research Group; September 26 1988.

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

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

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

74. **MDPU** 88-67, Phase II; Boston Gas Company Conservation Program and Rate Design; Boston Gas Company; March 6 1989.

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

75. **Vermont PSB** 5270; Status Conference on Conservation and Load Management Policy Settlement; Central Vermont Public Service, Conservation Law Foundation, Vermont Natural Resources Council, Vermont Public Interest Research Group, and Vermont Department of Public Service; May 1 1989.

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

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

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

77. **MDPU** 89-100; Boston Edison Rate Case; Massachusetts Energy Office; June 30 1989.

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

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

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

79. **MDPU** 89-72; Statewide Towing Association, Police-Ordered Towing Rates; Massachusetts Automobile Rating Bureau; September 13 1989.

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

80. **Vermont PSB** 5330; Application of Vermont Utilities for Approval of a Firm Power and Energy Contract with Hydro-Quebec; Conservation Law Foundation, Vermont Natural Resources Council, Vermont Public Interest Research Group; December 19 1989. Surrebuttal February 6 1990.

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

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

81. **MDPU** 89-239; Inclusion of Externalities in Energy Supply Planning, Acquisition and Dispatch for Massachusetts Utilities; December 1989; April 1990; May 1990.

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

82. **California PUC**; Incorporation of Environmental Externalities in Utility Planning and Pricing; Coalition of Energy Efficient and Renewable Technologies; February 21 1990.

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

83. **Illinois Commerce Commission** Docket 90-0038; Proceeding to Adopt a Least Cost Electric Energy Plan for Commonwealth Edison Company; City of Chicago; May 25 1990. Joint rebuttal testimony with David Birr, August 14 1990.

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

84. **Maryland PSC** 8278; Adequacy of Baltimore Gas & Electric's Integrated Resource Plan; Maryland Office of People's Counsel; September 18 1990.

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

85. **Indiana Utility Regulatory Commission;** Integrated Resource Planning Docket; Indiana Office of Utility Consumer Counselor; November 1 1990.

    Integrated resource planning process and methodology, including externalities and screening tools. Incentives, screening, and evaluation of demand-side management. Potential of resource bidding in Indiana.

86. **MDPU** 89-141, 90-73, 90-141, 90-194, and 90-270; Preliminary Review of Utility Treatment of Environmental Externalities in October QF Filings; Boston Gas Company; November 5 1990.

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

87. **MEFSC** 90-12/90-12A; Adequacy of Boston Edison Proposal to Build Combined-Cycle Plant; Conservation Law Foundation; December 14 1990.

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

88. **Maine PUC** 90-286; Adequacy of Conservation Program of Bangor Hydro Electric; Penobscot River Coalition; February 19 1991.

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

89. **Virginia State Corporation Commission** PUE900070; Order Establishing Commission Investigation; Southern Environmental Law Center; March 6 1991.

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

90. **MDPU** 90-261-A; Economics and Role of Fuel-Switching in the DSM Program of the Massachusetts Electric Company; Boston Gas Company; April 17 1991.

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

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

    NEPCo rates for power purchases from the NESWC plant. Fuel price and avoided cost projections vs. realities.

92. **Vermont PSB** 5491; Cost-Effectiveness of Central Vermont's Commitment to Hydro Quebec Purchases; Conservation Law Foundation; July 19 1991.

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

93. **South Carolina PSC** 91-216-E; Cost Recovery of Duke Power's DSM Expenditures; South Carolina Department of Consumer Affairs; September 13 1991. Surrebuttal October 2 1991.

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

94. **Maryland PSC** 8241, Phase II; Review of Baltimore Gas & Electric's Avoided Costs; Maryland Office of People's Counsel; September 19 1991.

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

95. **Bucksport Planning Board;** AES/Harriman Cove Shoreland Zoning Application; Conservation Law Foundation and Natural Resources Council of Maine; October 1 1991.

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

96. **MDPU** 91-131; Update of Externalities Values Adopted in Docket 89-239; Boston Gas Company; October 4 1991. Rebuttal, December 13 1991.

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

97. **Florida PSC** 910759; Petition of Florida Power Corporation for Determination of Need for Proposed Electrical Power Plant and Related Facilities; Floridians for Responsible Utility Growth; October 21 1991.

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

98. **Florida PSC** 910833-EI; Petition of Tampa Electric Company for a Determination of Need for Proposed Electrical Power Plant and Related Facilities; Floridians for Responsible Utility Growth; October 31 1991.

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

99. **Pennsylvania PUC** I-900005, R-901880; Investigation into Demand Side Management by Electric Utilities; Pennsylvania Energy Office; January 10 1992.

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

100. **South Carolina PSC** 91-606-E; Petition of South Carolina Electric and Gas for a Certificate of Public Convenience and Necessity for a Coal-Fired Plant; South Carolina Department of Consumer Affairs; January 20 1992.

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

101. **MDPU** 92-92; Adequacy of Boston Edison's Street-Lighting Options; Town of Lexington; June 22 1992.

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

102. **South Carolina PSC** 92-208-E; Integrated Resource Plan of Duke Power Company; South Carolina Department of Consumer Affairs; August 4 1992.

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

103. **North Carolina Utilities Commission** E-100, Sub 64; Integrated Resource Planning Docket; Southern Environmental Law Center; September 29 1992.

    General principles of integrated resource planning, DSM screening, and program design. Review of the IRPs of Duke Power Company, Carolina Power & Light Company, and North Carolina Power.

104. **Ontario Environmental Assessment Board** Ontario Hydro Demand/Supply Plan Hearings; *Environmental Externalities Valuation and Ontario Hydro's Resource Planning* (3 vols.); October 1992.

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

105. **Texas PUC** 110000; Application of Houston Lighting and Power Company for a Certificate of Convenience and Necessity for the DuPont Project; Destec Energy, Inc.; September 28 1992.

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

106. **Maine Board of Environmental Protection;** In the Matter of the Basin Mills Hydroelectric Project Application; Conservation Intervenors; November 16 1992.

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

107. **Maryland PSC** 8473; Review of the Power Sales Agreement of Baltimore Gas and Electric with AES Northside; Maryland Office of People's Counsel; November 16 1992.

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

108. **North Carolina Utilities Commission** E-100, Sub 64; Analysis and Investigation of Least Cost Integrated Resource Planning in North Carolina; Southern Environmental Law Center; November 18 1992.

Demand-side management cost recovery and incentive mechanisms.

109. **South Carolina PSC** 92-209-E; In Re Carolina Power & Light Company; South Carolina Department of Consumer Affairs; November 24 1992.

DSM planning: objectives, process, cost-effectiveness test, comprehensiveness, lost opportunities. Deficiencies in CP&L's portfolio. Need for economic evaluation of load building.

110 **Florida Department of Environmental Regulation** 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. **Maryland PSC** 8487; Baltimore Gas and Electric Company, Electric Rate Case; January 13 1993. Rebuttal Testimony: February 4 1993.

Class allocation of production plant and O&M; transmission, distribution, and general plant; administrative and general expenses. Marginal cost and rate design.

112. **Maryland PSC** 8179; for Approval of Amendment No. 2 to Potomac Edison Purchase Agreement with AES Warrior Run; Maryland Office of People's Counsel; January 29 1993.

Economic analysis of proposed coal-fired cogeneration facility.

113. A. **Michigan PSC** U-10102; Detroit Edison Rate Case; Michigan United Conservation Clubs; February 17 1993.

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

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

DSM planning, program designs, potential savings, and avoided costs.

115. **Michigan 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. **Illinois Commerce Commission** 92-0268, Electric-Energy Plan for Commonwealth Edison; City of Chicago. Direct testimony, February 1 1994; rebuttal, September 1994.

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

117. **FERC** 2422 et al., Application of James River–New Hampshire Electric, Public Service of New Hampshire, for Licensing of Hydro Power; Conservation Law Foundation; 1993.

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

118. **Vermont 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. **Florida 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. **Vermont 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. **MDPU** 94-49, Boston Edison integrated resource-management plan; Massachusetts Attorney General. August 1994.

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

122. **Michigan 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. **Michigan 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. **New Jersey Board of Regulatory Commissioners** 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. **Michigan 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. **Michigan 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. **North Carolina Utilities Commission** E-100, Sub 74, Duke Power and Carolina Power & Light avoided costs; Hydro-Electric–Power Producer's Group. February 1995.

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

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

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

130. **DCPSC** Formal 917, II, Prudence of DSM expenditures of Potomac Electric Power Company; Potomac Electric Power Company. Rebuttal testimony, February 1995.

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

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

DSM cost recovery. Lost-revenue–adjustment mechanism for Consumers Gas Company.

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

Allocation of costs and benefits to rate classes.

133. **MDPU** 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. **Maryland 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. **North Carolina Utilities Commission** E-2, Sub 669. December 1995.

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

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

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

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

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

138 **Vermont PSB** 5835; Vermont Department of Public Service. February 1996.

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

139. **Maryland 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. A. **MDPU** 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. **MDPU** DPU 96-70; Massachusetts Attorney General. July 1996.

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

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

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

143. **Maryland PSC** 8725; Maryland Office of People's Counsel. July 1996.

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

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

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

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

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

147. **Vermont 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. **MDPU** 96-23, Boston Edison restructuring settlement; Utility Workers Union of America. September 1997.

Performance incentives proposed for the Boston Edison company.

149. **Vermont 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. **MDPU** 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. **MDTE** 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. **NH 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. **Maryland PSC** 8774; APS-DQE merger; Maryland Office of People's Counsel. February 1998.

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

154. **Vermont 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. **MDTE** 98-89, purchase of Boston Edison municipal streetlighting, Towns of Lexington and Acton. Affidavit, August 1998.

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

157. **Vermont 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. **MDTE** 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. **Maryland 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. **Maryland 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. **Maryland 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. **Connecticut 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. **Connecticut 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. **Washington 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. **Connecticut 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. **Connecticut 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. Virginia 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. **Ontario 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. **Connecticut 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. **Connecticut Superior Court** CV 99-049-7239; Connecticut Light and Power Company stranded costs; Connecticut Office of Consumer Counsel. Affidavit, December 1999.

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

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

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

173. **Ontario 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. **Connecticut 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. **Ontario 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. **NY 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. **MEFSB** 97-4; MMWEC gas-pipeline proposal; Town of Wilbraham, Mass. June 2000.

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

180. **Connecticut 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. **Connecticut 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. **MDTE** 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. **Connecticut 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. **Vermont 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. **New Jersey 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. **New Jersey 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. **Connecticut 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. **New Jersey 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. **NY 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. **MDTE** 01-56, Berkshire Gas Company; Massachusetts Attorney General. October 2001.

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

191. **New Jersey 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. **Vermont PSB** 6545; Vermont Yankee proposed sale; Vermont Department of Public Service. Direct, January 2002.

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

193. **Connecticut 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. **Vermont 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. **Connecticut 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. **Connecticut 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. **Ontario EB** RP-2002-0120; Review of transmission-system code; Green Energy Coalition. October 2002.

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

198. **New Jersey 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. **Connecticut 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. **Connecticut DPUC** 03-07-01; CL&P transitional standard offer; AARP. November 2003.

Application of rate cap. Legislative intent.

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

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

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

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

203. **NY PSC** Cases 03-G-1671 & 03-S-1672; Consolidated Edison Company Steam and Gas Rates; City of New York. Direct March 2004; Rebuttal April 2004; Settlement June 2004.

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

204. **NY 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. **Ontario EB** 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. **MDTE** 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. **NY 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. **NY 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. **Maryland 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. **British Columbia Utilities Commission** Project No. 3698388, British Columbia Hydro resource-acquisition plan; British Columbia Sustainable Energy Association and Sierra Club of Canada BC Chapter. Direct, September 2005.

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

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

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

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

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

213. **Connecticut 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. **Ontario 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. **Ontario Energy Board** Case EB-2006-0021; natural gas demand-side-management generic issues proceeding; School Energy Coalition. Evidence, June 2006.

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

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

Rate decoupling and energy-efficiency goals.

217. **Pennsylvania PUC** Docket No. 00061346; Duquesne Lighting; Real-time pricing; PennFuture. Direct, July 2006; surrebuttal August 2006.

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

218. **Pennsylvania PUC** Docket No. R-00061366, et al.; rate-transition-plan proceedings of Metropolitan Edison and Pennsylvania Electric; Real-time pricing; PennFuture. Direct, July 2006; surrebuttal August 2006.

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

219. Connecticut 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 September and October 2006.

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

220. Connecticut 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 August and November 2006; March, September, October, and November 2007; February, April, and May 2008.

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

221. NY PSC Case No. 06-M-1017; policies, practices, and procedures for utility commodity supply service; City of New York. Comments, November and December 2006.

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

222. Connecticut 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. PUCO Case No. 05-1444-GA-UNC; recovery of conservation costs, decoupling, and rate-adjustment mechanisms for Vectren Energy Delivery of Ohio; Ohio Consumers' Counsel. Direct, February 2007.

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

224. NY PSC Case 06-G-1332, Consolidated Edison Rates and Regulations; City of New York. Direct, March 2007.

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

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

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

226. Connecticut DPUC Docket 07-04-24, Review of capacity contracts under Energy Independence Act; Connecticut Office of Consumer Counsel, Joint Direct Testimony June 2007.

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

227. NY PSC Case 07-E-0524, Consolidated Edison electric rates; City of New York. Direct, September 2007.

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

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

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

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

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

230. CDPUC 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. Ontario EB-2007-0905, Ontario Power Generation payments; Green Energy Coalition. Direct, April 2008.

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

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

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

233. Ontario EB-2007-0707, Ontario Power Authority integrated system plan; Green Energy Coalition, Pembina 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. NY PSC Case 08-E-0596, Consolidated Edison electric rates; City of New York. Direct, September 2008.

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

235. **CDPUC 08-07-01**, integrated resource plan; Connecticut Office of Consumer Counsel. Direct, September 2008.

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