STATE OF MARYLAND

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of the Application of	**)**	
the Baltimore Gas and Electric	**)**	**Case No. 9036**
Company for Approval	**)**	
of a Gas Rate Increase	**)**	

DIRECT TESTIMONY OF

PAUL CHERNICK

ON BEHALF OF

THE MARYLAND OFFICE OF PEOPLE'S COUNSEL

Resource Insight, Inc.

AUGUST 15, 2005

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EXHIBITS

I. Identification and Qualifications

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

A: I am Paul L. Chernick. I am president of Resource Insight, Inc., 347 Broadway, Cambridge, 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 summarized 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, 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, Ontario Energy Board, 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. 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.

II. Introduction and Summary

Q: On whose behalf are you testifying?

A: My testimony is sponsored by the Office of People's Counsel.

Q: What is the purpose of your direct testimony?

A: I address issues of cost allocation and rate design.

Q: What are your conclusions and recommendations in this matter?

A: My major conclusions and recommendations are as follows:

- The revenue allocation to Schedules IS, AIS, and ISG should be increased to the system-average return to reduce the extent of residential overpayment.
- Any reduction in the Company's requested rate increase should first be applied to the residential class to bring its return down to the Company allowed rate of return.
- The Company should improve its future cost-of-service studies to address the issues discussed in Section III.B below.
- The Schedule D customer charge should not be increased.
- The Commission should direct the Company to design the IS and AIS rates to provide adequate incentives to interrupt and to ensure that customers who cannot or will not comply with interruption requests will take service on a firm rate.
- Until the Company has adequate interruptible rates in place, the alternative-fuel-capability requirement should not be eliminated.
- The Gas Air Conditioning rate, Rider 5, should not be eliminated.
- The Commission should reject the Company's proposal to charge for residential service upgrades for all "non-standard" gas applications and require any such charges to be based on the shape of the added load, not on arbitrary end-use classifications.

III. The Company's Cost-of-Service Study

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

A: The cost allocation process assigns the utility's total revenue requirement to the various classes. The process is generally driven by some concept of fairness. It is a generally accepted principle that allocation based on cost causation results in an equitable sharing of costs.

Q: What were the results of BGE's cost-of-service study?

A: The Company's cost-of-service study indicates that in 2003 the residential class (Schedule D) was paying 22% more than the Company's average rate of return.

A. Allocation of Revenue Increase

Q: How does the Company propose to use the results of the Cost-of-Service Study in allocating the rate increase among rate classes?

A: The Company proposes to bring class rates of return closer to the system average by allocating the requested revenue increase in two steps. First, BGE calculates an adjustment to the 2003 revenue of each class so that the class's earned return is within 10% of the system average of 7.6%. BGE adjusts Schedule D's revenues downward to reduce its return from 9.24% to 8.35% and increases the revenues of Schedule C, AIS, IS, and ISG to raise their returns to about 6.85% (DR Staff 4-14 at Att. 1).[1]

The adjustments calculated in the first step of BGE's allocation process require a net increase over 2003 revenues of $2,509,335 (Testimony of Company Witness Laurie H. Duhan at Exhibit LHD-2, Sheet G-2). The Company apportions the remainder of the requested revenue increase (that is, $52,646,449 net of the $2,509,335) in proportion to class current revenues plus the adjustment calculated in Step 1.

Under BGE's proposal, the residential ratepayers would receive a 14.4% increase in base rates, and a 4.8% increase in their total bill, on average.

Q: What increase would the residential class receive if the Company allocated the proposed increase to equalize class rates of return?

[1] The Company makes an exception for Schedule PLG. Its 48.4% rate increase is only enough to bring it up to a return of 0% (Testimony of Company Witness Laurie H. Duhan at 11).

A: Schedule D would receive a base rate increase of $21,627,520, or 11.6% over current base revenues. (DR OPC 5-43)

Q: What is BGE's rationale for choosing a 10% bandwidth?

A: The Company considers this to be a "reasonable" allocation of the revenue increase as explained in its response to DR OPC 5-42:

> In this instant case, BGE finds that when looking at the impact on all customer classes ±10% is a reasonable band around the system average.

If BGE's bandwidth approach is used to apportion a base rate increase, the impact on the bills of Schedule C customers may be the limiting factor in the size of the bandwidth. Since Schedule C has the lowest class rate of return (aside from the very small PLG class), the use of a fixed bandwidth has the largest effect on this rate class. Under the 10% bandwidth, the Schedule C rate class receives a 39.4% base rate increase. Equalizing rates of return across classes would bring Schedule C's base rate increase to 46.8% (DR OPC 5-43).

Q: Do you agree that BGE cannot reduce the allocation of revenues to the residential class without giving other rate classes unreasonable increases?

A: No, for the following reasons:

- The impacts on customer bills, not simple formulas, should guide reallocation of revenues among rate classes.
- There are reasonable adjustments to BGE's proposed allocation that would reduce the residential class's share of the rate increase.
- Previously, BGE proposed a smaller bandwidth, even though that produced a disproportionately large increase to the residential class. The Commission accepted this bandwidth.
- The allocation of the revenue increase, including the choice of a bandwidth, should depend on the size of the allowed revenue increase.

- Residential customers may have been paying more than their fair share for longer than BGE's cost-of-service studies indicate.
- Schedule D's relative return may be greater in the test year than in 2003.

Q: Why is the Company's simple bandwidth formula an inadequate approach to revenue allocation?

A: The revenue shifts allowed by the bandwidth approach do not identify the limits imposed by principles of rate continuity or avoidance of rate shock. A bandwidth can limit one class to a trivial increase while allowing an enormous increase for another class. Under a 10% bandwidth, for example, a rate class being moved from a 0.55 relative return (like Schedule C) can face a large rate increase, while a rate class moving from a 0.84 relative return (like Schedule IS) would be limited to a small rate increase, leaving it well below its fair share of system costs. Selecting the bandwidth to keep the impact on one class tolerable can severely restrict reallocation of revenues among other classes, even if full equalization for them would cause no rate shock.

Q: Can reasonable adjustments to BGE's proposal be made that would reduce the allocation of revenue requirements to the over-earning residential class?

A: Yes. The Company has found reasonable the raising of Schedule-C base rates by 39.4%, and total bills by 6.6%. Since the Company's proposal would increase Schedule IS, AIS and ISG base rates of 21% to 23% and total bills of only 2% to 3% (both much lower than the Company accepts for Schedule C), leaving all three Schedules under-earning, there is room for further reallocation of revenues to bring the residential return closer to system average.

Q: Please describe your revenue-allocation proposal.

A: I propose the following: Start with a revenue allocation that equalizes rates of return, then reallocate revenues from the Schedules with the large increases—in this case, Schedules C and PLG—to the residential class, until the increases to C and PLG are reasonable. Under this approach, if the increases to Schedules C and PLG are limited as proposed by the Company, the residential class receives an increase of $25,735,063 or 13.8%, an amount $1,241,430 less than the proposed increase. The allocation process I describe is shown in Exhibit PLC-2.

Q: Would the resulting increases to Schedules IS, AIS, and ISG be reasonable?

A: Under my proposal, the base rate increases to these classes would be 30%, well below the level BGE found acceptable for Schedule C. More importantly, the total bill impacts are very low: a 2% increase for Schedules ISG and IS and a 3.5% increase for Schedule AIS.

Q: How has the BGE allocated revenues to the residential class previously?

A: In Case No. 8697, when BGE's cost-of-service study indicated that the residential class was earning less than the system average rate of return, the Company proposed a smaller 7% bandwidth and allocated 86% of the requested increase to the residential class. The resulting 23% increase in residential base rates and a 11% increase in total bills were 30% to 40% more than the requested system increase (Testimony of Company Witness D. Douglas DeWitt in Case No. 8697 at Exhibit DDD-3, Sheet G-1).

Now that the tables are turned, the Company proposes a larger 10% bandwidth to limit the increase to the non-residential classes.

Q: Why do you suspect that the residential class may have been paying more than its fair share for longer than BGE's cost-of-service studies indicate?

A: As the Commission stated in Case No. 8697 (Order at 22), BGE's past cost-of-service studies indicated that "the return of the residential class historically has been far below the system average despite repeated efforts to bring it in closer alignment." The dramatic shift to the 2003 cost-of-service study, which shows the residential class substantially over-earning coincides with a change in the source of the residential load data. As the Company's response to DR Staff 5-14 explains:

> The Company had not implemented a class load research study for Schedule D [in BGE's previous rate case]. The hourly loads and sendout day loads for this class were determined as the difference between the total system sendout and the sum of the loss-adjusted loads of the remaining classes.

Q: How have class gas consumption and revenues changed between the 2003 data used in the cost-of-service study and the test year?

A: First, since 2003, the residential share of revenues has increased and its share of throughput has fallen, while the reverse has occurred for general service customers. The table below presents a comparison of usage and revenues by rate sub-class for 2003 and the test year. Residential revenues have increased and usage has declined, while the reverse has occurred for general-service customers. The 2003 data thus may have understated the residential class's relative rate of return.

Change in Gas Consumption and Revenues

	Residential Share of Total	Total	D	C	AIS	IS	BSC
Throughput (Million Dth)							
2003	43.1%	109.9	47.4	31.0	1.2	21.7	8.6
Test Year	41.2%	107.0	44.1	29.9	1.3	22.1	9.5
Base Revenues (Millions of Dollars)							
2003	70.5%	261.9	184.6	59.3	1.1	10.5	6.4
Test Year	72.4%	258.2	186.8	54.6	1.2	10.7	4.8

The changes in revenues per therm from 2003 to the test year may have occurred due to operation of the weather-adjustment mechanism. It is not clear that the actual ratio of revenues to sales for 2003 was representative of BGE's base rates, or that using the indicated return from 2003 is representative of the residential class contribution.

Q: What revenue allocation do you recommend?

A: The revenue allocation to Schedules IS, AIS, and ISG should be increased to move these classes towards the system average return so as to reduce the extent of residential overpayment. Then any reduction in the Company's requested rate increase should first be applied to the residential class to bring it down to the Company allowed rate of return; any additional reduction can be spread among all classes.

B. Evaluation of BGE's Cost-of-Service Study

Q: Please summarize your evaluation of BGE's cost-of-service study.

A: I have identified a number of problems with the Company's classification and allocation decisions.

- The coincident peak and non-coincident peak allocators (PDAY and NCP, respectively) exclude some Schedule AIS, IS, and ISG loads.
- The Company overstates the NCP of its residential and small commercial sub-classes.
- The services allocator is based on an outdated analysis that cannot be reviewed and on annual updates that over-allocate costs to the residential class.
- The classification and allocation of environmental costs according to distribution demand does not reflect the cause of these costs.

- The Company's allocation of administrative & general expenses on labor ignores the many non-labor-rated A&G expenses, which would be better captured by an allocation on plant.

Q: What is the effect of the Company's error on its costs?

A: Most, and probably all, of the errors overstate the allocation of costs to the residential class.

1. Coincident Peak Allocator

Q: What loads are excluded from the Company's coincident-peak allocator?

A: The Company assumes that the throughput of Schedules IS and AIS customers on the system-peak day does not contribute to the need for peaking resources. While interruptible customers' Critical Use Gas is a very small portion of BGE's total peak, it is firm load and should be reflected in the peak-day allocators of these two classes. In addition, the proposed elimination of automatic interruption for Schedule AIS and the requirement that Schedule IS customers maintain alternative fuel capability may increase participation in Schedule IS and hence the level of Critical Use Gas.

Q: Other than these intentional exclusions, is the PDAY allocator correct?

A: No. According to Company Witness Duhan (Testimony at 6), the peak-day allocator, PDAY, is "the firm sub-classes' contribution to the firm sendout on the day of the year with the highest sendout." As documented in the spreadsheet HOURLY LOADS2003.xls (provided in response to DR OPC 5-2 at Attachment 1), the Company designated January 27, 2003 as the peak day and used the sub-classes' sendout in that day to determine the PDAY factors.

There are two problems with this derivation of the allocator. First, according to DR OPC 6-4, January 23, not January 27, was the peak day in 2003 and indeed, the sum of the estimated sub-class firm loads on January 23 is higher than the sum of the estimated firm loads on January 27.

Second, the Company sets ISG's PDAY load at a contract billing demand of 240,000 therms (DR OPC 6-51). However, ISG's actual load on January 23 was 259,508 therms.

Q: Is it appropriate to use an ISG contract billing demand of 240,000 therms?

A: No, for two reasons:

- ISG's actual load can exceed its contract billing demand. Since ISG is a firm customer, BGE must plan its system to meet the greater of ISG's contract billing demand and actual demand.
- The cost-of-service study is based on 2003 cost and load conditions, and ISG's contract billing demand was 300,000 therms in calendar year 2003. (DR OPC 6-44).

2. Non-Coincident-Peak Allocator

Q: What loads are excluded from the non-coincident-peak allocator?

A: First, BGE does not consider the hourly demands of AIS and IS customers on demand-free days in the determination of the NCPs of these classes.[2] The Company acknowledges that the maximum hourly demands of these classes could have occurred on a demand-free day (DR OPC 6-29).

Second, BGE considers loads in only three winter months, January through March (HOURLYLOADS2003.xls, provided in response to DR OPC 5-2 at Attachment 1). The maximum hourly demand of large C&I customers, however, may occur in off-peak months.

[2]The tariff defines "demand-free" days as follows: "the Company may at its option designate any gas day as "demand free"….Any gas used during a Demand Free Day will not be considered when determining a Customer's Billing Demand" (Exhibit LHD-5).

Third, the 2003 NCP of the AIS class may not reflect the elimination of the automatic interruption at a preset temperature. Under BGE's proposal, AIS customers would no longer be automatically interrupted on cold, high-demand days, so this change could result in an increase in the AIS class's NCP. Since this change in the tariff alters the nature of the customers' loads in this class, it should be reflected in the load data used in the cost-of-service study. It is not clear from the Company's response to DR OPC 6-53 whether the BGE properly administered the tariff in 2003, and hence whether any adjustment to the 2003 load data would be appropriate.

Fourth, the NCPs used in the cost-of-service study for interval-metered customers (particularly Schedules IS, AIS, and ISG) are not equal to, and may be less than, their actual 2003 maximum hourly demand. The NCPs for these classes are not the sums of actual metered quantities. Instead, BGE for some reason had to reconcile the hourly load data from the AMR devices to monthly load figures using the same method applied to sample load data. In DR OPC 6-51 the Company describes this calculation for ISG:

> Consistent with the practice for developing the hourly load data for all other subclasses…, the hourly interval data for ISG for each calendar month are scaled to the level of calendar month ISG consumption as reported on Company financial statements.

The Company does not explain why the actual data for AMR customers had to be adjusted. In fact Ms. Duhan (Testimony at 8) indicates that the Company had reliable metered data for all customers in the sub-classes with AMR meters:

> Customers receiving service under Schedules IS,...AIS,...ISG...and Daily-Metered customers receiving service under Schedule C have Automated Meter Reading Devices (AMR) that provide load data on an hourly basis so that no estimation is necessary for these customers.

Q: Has the Company always limited NCP to winter months?

A: No. In Case No. 8829, the cost-of-service study used annual NCP data (DR Staff 5-7).

Q: What is the Company's rationale for ignoring demands in summer months?

A: The Company explains that it

> made this change because a Billing Demand was implemented for interruptible service customers. The Billing Demand is the maximum winter day use, recognizing that there is non-winter distribution capacity available on the system. Recognizing that there is distribution capacity available in non-winter months when determining the NCP is consistent with excluding non-winter use when determining a customer's Billing Demand. (DR Staff 5-14)

Q: Is this a reasonable explanation?

A: No. Rate design, which attempts to affect the behavior of individual customers, is not the same as cost allocation, which apportions the system costs among the classes. Whether or not a seasonal demand charge makes sense for rate design, that rate-design decision does not require any particular class cost allocation. A significant portion of interruptible-service distribution revenues are derived from a commodity charge that is not seasonally differentiated. Even the IS and AIS demand charges are based on maximum-day use in five months (December to March), not just the three months BGE used in the NCP computation (January to March). The firm commercial delivery rates are not seasonally differentiated at all. The Company has not explained why it chose to use part of the demand charge of the Schedule IS rate design, rather than the Schedule C rate design, in determining which months to include in the NCP computation.

The Company has not demonstrated that high class loads in months other than January through March have no effect on distribution costs. The whole point of using the NCPs for determining distribution costs is that the residential peak will tend to drive equipment sizing in largely residential areas, the commercial peak will tend to drive equipment sizing in largely commercial areas, the peak load of the Schedule IS customers (or even one or two neighboring customers) will tend to drive the local delivery capacity, and ISG's peak load (or the contract load BGE must be prepared to meet) drives the sizing of supply for that large load. In April and June there may be no constraints at the BGE city-gates or in the heating-driven residential and commercial areas, but the mains serving very large customers may be fully loaded.

Ignoring peaks outside the three winter months defeats the point of using the NCP as an allocator of distribution plant, which is to reflect the geographic diversity of the timing of peak loads.

Q: Does the Company explain why it ignored the load of IS and AIS customers on demand-free days?

A: No. Perhaps BGE assumes that the distribution system is not constrained on the demand-free days in winter.

Q: Is there any reason to include in the NCP hours in which distribution capacity is not constrained?

A: Yes, for two reasons. First, as discussed above, even if some elements of the distribution system have extra capacity on demand-free days, there may certainly be parts of the local distribution system that are heavily loaded on those days, especially near large IS customers.

Second, this treatment gives interruptible classes special treatment that firm customers do not receive. The NCP computations for firm customers do not exclude loads on days when the distribution system is not constrained. Using inconsistent definitions of an allocator for various classes is very unusual and highly suspect.

Q: How has BGE overstated the NCP of the residential class?

A: The NCP of the residential class is estimated by sub-class, rather than for the rate class as a whole. BGE's approach assumes essentially that NH and H residential customers are on different portions of the distribution systems. It is more likely that non-heating and heating residential customers are located in the same areas and on the same distribution systems. BGE's approach thus ignores the diversity of load between heating and non-heating customers. Therefore, BGE should use class non-coincident peak for the residential class as a whole in the NCP allocator. The NCP for the residential class as a whole is about 1% less than the sum of the heating and non-heating NCPs (DR OPC 5-26).

3. Allocation of Environmental Costs

Q: How does BGE treat the environmental cleanup costs of the Spring Gardens site?

A: Spring Gardens was the site of one of the country's largest coal-gasification facilities, starting in 1855, with expansions at least into the 1920s and operations continuing to the early 1970s. This gas-manufacturing process resulted in significant site contamination, which BGE is now remediating. The Company classifies these costs as 100% demand-related and functionalizes them as 100% distribution-related, and allocates them on class non-coincident peak.

Q: What rationale does BGE provide for this approach?

A: The Company states its rationale as follows:

> The majority of these cost are associated with the oil recovery system for manufactured gas facilities which had previously served all customer classes. (DRs OPC 5-4, 5-5)

> These costs are classified as demand on the principle that manufactured gas was used to meet system peak demands. (DR OPC 5-5)

The Company's point seems to be that it uses the NCP distribution allocator to ensure that the cost is spread over all customers, not just sales customers.

Q: Is the Company's approach appropriate?

A: While BGE is correct to insist that delivery customers not escape the stranded environmental costs of cleaning up the mess created for them and their predecessors, the allocator it selected is inappropriate. The environmental clean-up costs should be allocated on the basis of the past service that created the damage.

Q: How does BGE's treatment of this cost fail to reflect the cause of the environmental contamination?

A: The environmental damage from distilling coal to produce gas is clearly a function of the amount of fuel produced. It appears that Spring Gardens was a baseload supply facility for BGE (and its direct predecessor, the Gas Light Company of Baltimore)—perhaps its *only* gas-supply facility until the conversion of the system to pipeline natural gas after World War II. The current environmental problems are not the result of the peak capacity of the plant.[3] Had the facility only operated as a peaking facility, supplementing some other baseload supply, the pollution burden might be orders of magnitude lower. Therefore, to the extent that these costs are allocated according to the cause of the contamination, they should be allocated according to annual commodity. Since there was no delivery service when Spring Gardens was manufacturing gas, the commodity measure should be throughput, not sales.

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[3]Costs related to the removal of the gasification equipment might be capacity-related, but the Spring Garden costs in this proceeding appear to be related to removing gasification wastes, not plant structures.

Q: Is the Spring Gardens cleanup at all distribution-related?

A: The Spring Gardens site currently houses a gas control and dispatching center, gas-distribution warehousing, maintenance and construction operations, an LNG storage facility, and supporting office operations for the Company. To the extent that the current use of the site increases the cost of the clean-up, a *portion* of the clean-up cost might reasonably be allocated on some distribution and/or production allocator.

I have not seen any evidence of any such effect of current operations on the cost of the environmental cleanup.

Q: How should the environmental cleanup costs be allocated?

A: Based on the source of the contamination, the costs should entirely be allocated on throughput. If current operations affect the cost, the choice of allocator is a matter of judgment. In Case No. 8697 BGE's cost-of-service-and-rate-design witness, Mr. D. Douglas DeWitt, agreed that it was reasonable to treat a portion of the Spring Gardens cleanup costs as "incurred as a result of the manufacture of the commodity" and suggested an allocator of 50% CP demand and 50% throughput (DeWitt Rebuttal Testimony at 21). Since some customers' loads are not included in the CP allocator, the allocator would no longer be appropriate. Since the Company has not established that *any* part of the Spring Gardens cleanup costs was incurred as a result of any factor other than "the manufacture of the commodity," throughput appears to be the only applicable allocator.

4. Allocation of Services

Q: How did the Company allocate services plant investment?

A: The Company estimated service investment by subclass by updating its 2002 allocation of services, to reflect additions, retirements, replacements, and conversions of services in 2003. The 2002 allocation was in turn a revision of

2001 services; the Company seems to have applied the same approach back to about 1990. Thus, the 2003 allocation was derived from the base year allocation (roughly 1990) plus several annual updates.

Q: Please describe the Company's 2003 revision of services allocation.

A: While this description uses the specific years 2002 and 2003 for clarity, the Company appears to have gone through the same process each year. The Company appears to have started with just five categories of changes in service costs for 2003: total retirements, total replacements, additional services for new residential construction, upgraded services to convert non-heating residential customers to gas heat, and service additions for industrial and commercial customers. The Company then allocated these changes to the sub-classes in three steps:

1. First, BGE allocated 2003 retirements and replacements among the sub-classes in proportion to the sub-class share of the 2002 allocation of total services plant.
2. Second, BGE assigned the additions for both residential construction and residential conversions to the residential heating sub-class.
3. Third, BGE allocated the non-residential additions between the firm commercial-heating sub-class and the IS class in proportion to the number of new customers in each class.

Q: Is this updating process appropriate?

A: No. The updating method

- improperly assumes that retirements and replacements are equally likely for brand-new services as for older services;
- improperly assumes that the large number of residential conversions do not reduce the service investment for residential non-heating customers;

- improperly allocates to the residential non-heating class replacements for services that no longer exist (for customers who are no longer in the non-heating subclass).

The Company's update for 2003 actually increases the share of services plant allocated to residential non-heating customers, even though the number of customers in that subclass has been shrinking due to heating conversions.

Q: Have you corrected these errors?

A: Yes. Using data provided by BGE, I have backed through from the 2002 services allocation to the 1997 allocation.[4] This computation is shown in Exhibit PLC-3. I have then added back in the Company's reported changes in services plant, using the following steps for each year:

1. First, I allocated replacements on remaining 1997 investment, so that I did not treat new services as being replaced.[5] A more detailed replacement schedule could be developed from vintaged retirement data, but I do not have any such data.
2. Second (like BGE), I added conversions to the residential heating subclass.
3. Third, I allocated retirements on the dollars of new services that would have been associated with retirements.[6] Those are the replacements and the heating conversions; I treated the conversions as increasing retirements in the residential non-heating class.

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[4]I did not have any information on the allocation of the industrial and commercial service additions among the general-service classes, so I assumed they all had been allocated to the CH subclass (which had been allocated 98.8% of 2003 non-residential service additions). This assumption should not affect the residential allocation.

[5]This probably overstates the allocation to residential non-heating, since it is unlikely that a service would be replaced early in a year and then replaced later in the year as part of a conversion.

[6]Few services would be retired without replacement.

4. Fourth, I assigned the new growth investments to the residential and commercial heating subclasses, as BGE did.[7]
5. Fifth, for 2003, I allocated on the sum of other 2002–2003 changes a large discrepancy between BGE's computation of the change in plant and BGE's reported total change. The Company made a similar adjustment for 2003.
6. Finally, I summed the previous year's investment and the five categories of changes today, to estimate the next year's investment.

These computations are summarized in Exhibit PLC-4.

Q: What is the effect of these corrections on the services-plant allocators?

A: The corrected allocation is significantly smaller for residential non-heating and higher for residential heating and various commercial classes. The net effect as shown in the table below is a reduction of over one percentage point in the share of service costs allocated to the residential class as a whole.

Correction for 1998–2003 Updates

Services Allocators	BGE	Corrected	Difference
D	9.82%	5.32%	-4.50%
DH	68.56%	71.93%	3.37%
C	1.06%	1.11%	0.05%
CH	11.37%	12.06%	0.69%
CL	8.45%	8.82%	0.36%
AIS	0.20%	0.21%	0.01%
IS	0.47%	0.49%	0.02%
PLG	0.01%	0.01%	0.00%
BS/ISG	0.05%	0.06%	0.00%

Q: Is the corrected allocator above your best estimate of the share of services attributable to each class?

[7] For 2003, I included in this column retirements BGE assigned to Private Area Lighting.

A: No, for two reasons. First, BGE only provided data from which I could correct the allocation of the last six annual updates of service plant. The Company appears to have used this approach since about 1990, so roughly another seven annual updates have not been accounted for. A similar correction to those updates would probably shift more of the allocator from residential (particularly non-heating) to commercial classes.

Second, the starting point for the annual allocation updates appears to have been a study performed in 1990 or before. It is not clear how well this study accounted for the effect of the customer class and usage on the diameter, length and cost of a service. Since BGE does not appear to maintain data on the number of gas services on its system (DR OPC 5-39), let alone by class or sub-class, it is unlikely that BGE has accounted for the sharing by many residential customers of a single service line to a multi-family building.

Q: How important might the latter factor be?

A: The sharing of services by customers in multi-family buildings could be significant. While BGE was not able to provide any information of the mix of housing types for its residential customers in this proceeding (DR OPC 5-40), its responses in Case No. 8697 indicated that 16% of its heating customers were in multi-family buildings and another 29% in row houses (DR OPC 5-8, Case No. 8697).

Some 20% of housing units in the Baltimore Metropolitan Area, as defined in the 1998 Census of Housing, were in multi-family housing, and nearly 30% were in row houses, as follows: [8]

[8]The data do not include whether the attached housing had separate services for each unit.

Units in Structure	Share of Year-Round Stock
1, detached	51%
1, attached	28%
2 to 4	6%
5 to 9	4%
10 to 19	7%
20 to 49	1%
50 or more	3%
Mobile home	2%

Of the housing units heated by gas, fully a third were rental units, which are heavily weighted towards multi-family.

Assuming that each residential building has a single service, and dividing the number of residential units by the number of units in each building, might produce an estimate of the number of residential services 15% to 20% less than the number of residential customers.

While some commercial accounts may also share services, the actual residential share of services is likely to be significantly less than that indicated by the correction I present above for the 1997–2003 updates.

5. *Administrative and General Expenses*

Q: How does BGE allocate Administrative & General costs?

A: The Company allocates most Administrative and General expenses on labor.

Q: What problem do you see in this treatment of Administrative & General expenses?

A: Administrative & General expenses are incurred to support a variety of other functions, but the embedded-cost study treats most A&G Accounts as though they were driven by only one kind of expense, labor. The only exceptions are Accounts 924 Property Insurance, 925 Injuries and Damages (which are clearly plant-related and BGE allocates them accordingly) and 930 Miscellaneous (which BGE allocates on both plant and labor).

Only Account 926, employee pensions and benefits, should be considered labor-related. The remaining A&G consists of such expenses as

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

These costs are driven by BGE's entire operation, including labor, other O&M and plant investment. The Company's approach fails to reflect corporate overhead associated with plant investment, such as planning, siting, property-tax negotiation and litigation, and related public relations.

The treatment of these costs should be revised to reflect administrative costs related to plant.

IV. Rate Design

Q: Which rate-design proposals will you comment on?

A: I will address the following rate-design proposals:

- An increase in the residential customer charge from $12.25 to $13.25
- Penalty Charges for Interruptible Service Schedules IS and AIS.
- The elimination of Rider 5—Gas Air Conditioning.
- Introduction of gas extension charges to residential customers with "non-standard" gas applications, such as pool heaters and gas generator.

- Elimination of the requirement that Schedule IS customers maintain alternative fuel capability.
- Change in the conditions under which customers on Schedule AIS will be interrupted.

A. Residential Customer Charge

Q: What is BGE's proposal on the residential customer charge?

A: The Company proposes to increase the customer charge from $12.25 to $13.25 per month, to "recover all of the customer-related costs" indicated by the cost-of-service study (Duhan Testimony at 14).

Q: Does the Company's Cost-of-Service Study justify a $13.25 residential customer charge?

A: No. The Company's cost-allocation study does not justify this level of fixed charges. The cost study and the Company's use of the study are flawed, for the following reasons:

- The cost study treats too large a portion of A&G expense as customer-related.
- The Company bases the customer charge on an average cost per customer that it derives from the cost allocation study. Using an average cost per customer does not take into account the effect of customer size on cost.
- The Company's study indicates that the customer costs of the non-heating residential customers is $12 while that of the heating customers is $13.46 (DR OPC 5-44). Even according to BGE's own study, raising the customer

charge will result in subsidization of heating customers by non-heating customers.[9]

- The Company's overstates the allocation of services (an important component of customer costs) to the residential non-heating sub-class by about 85%.

Currently more than 40% of base revenues are recovered through a charge that customers cannot avoid. Given that BGE has seen its design day requirement grow by 71,000 Dth since 1999 (Duhan Testimony at 33), and projects increasing constraints on its distribution system, it would make more sense to increase the delivery charge and encourage more efficient use of gas.

Q: What is your basis for stating that too much of A&G is treated as customer-related?

A: The Company's cost-of-service study allocates most of A&G on labor and as a result classifies about 60% as a customer-related cost. As discussed in Section III.B.5, more A&G expense should be allocated on plant. Since only 40% of plant is classified as customer-related, allocating A&G expense on plant instead of labor would reduce the customer allocation.

Q: What customer-related costs were over-allocated to the residential class as a whole?

A: As described in Section III.B.5 above, A&G expenses and services were over-allocated to the residential class.

Q: What customer-classified costs should not be included in the calculation of the customer charge?

[9] Since the heating customers pay the same amount for their more expensive load shape, they are also subsidized by non-heating customers in the commodity charge and the cost of gas (DR Staff 1-21).

A: A portion of many customer-classified costs vary with the size of the customer (in revenues, sales, or demand), and therefore, should be recovered through the commodity charge. For example, the service cost for small residential customers is likely to be lower than for large ones. Large residential customers are likely to be single-family homes, each using a fairly long service drop. Small customers are more likely to share services in multi-family housing or townhouses, or perhaps in row houses with individual, but short, service lines.

Other costs that are classified as customer-related will also vary with the customer's use. For example, uncollectible accounts and collection expense are likely to be larger for large customers than for small customers (since the large customers have larger bills to become uncollectible).[10] A large customer with a large bill is more likely to place demands on customer service to explain his bill, and on the meter department to test his meter.

Q: How does BGE's cost-of-service study indicate the effect of customer usage on customer-classified costs?

A: The Company's cost-of-service study recognizes that the customer-related costs are equal for customers across classes, or even in a particular class. BGE allocates most customer costs among subclasses so that classes consisting of large customers pay more per customer than classes of small customers.

Unfortunately, BGE forgets about the association of cost with size when it calculates the residential customer charge as an average over the entire class.

Q: How has the Company's services allocator overstated residential NH customers' share of total residential services?

[10] The Company believes that a recent increase in bad debt was caused by the increase in commodity cost; this would be much more important for large customers than for small ones.

A: As discussed in Section III.B.4, above, BGE has allocated an excessive share of the annual service-cost updates (and apparently also of the initial allocation) to the residential non-heating sub-class.

In addition to the errors discussed in Section III.B.4, while BGE apparently reduces the number of residential non-heating customers by the number of conversions to space heating, it apparently does not equivalently reduce the gross or net plant for non-heating services. In Section III.B.4, I partially correct BGE's allocation of services; where a new service was installed for the conversion, I increase non-heating retirements. My corrections do not shift the service cost from non-heating to heating when no service replacement was needed. There may be many such conversions. While BGE has not provided the number of services replaced for heating conversions, it reports that 871 meters were changed out in the conversion of residential customers to heating in 2003. In the same year, non-heating customers decreased 3,574. Perhaps three quarters of heating conversions do not require replacement of the service and meter, and yet in the case of these conversions the service cost remains in the non-heating subclass.

Q: What is your recommendation regarding the residential customer charge?

A: The Schedule-D customer charge should not be increased above the current $12.25/month.

B. Interruptible Service Schedules IS and AIS

Q: What penalties for non-interruption for the IS and AIS rate schedules?

A: The rate schedules contain the following two penalty charges:

- $1 per therm for gas used in excess of Critical Use Gas during an interruption.

- An increase in the demand charge effective for the 12 months following the non-interruption. In the proposed IS rate, the demand charge would be increased from $3.07 per Dth to $7.42 per Dth. In the proposed AIS rate, the demand charge would be increased from $3.81 per Dth to $10.75 per Dth.

Q: Are these penalty provisions adequate?

A: No. There are two problems with the penalties. First, for the same load, the customer's bill under Schedule IS would be lower than under Schedule C even if the customer fails to interrupt, giving the customer no incentive to declare itself to be a firm Schedule-C customer. Second, the design of the penalty limits Schedule IS customer's incentives to shorten the period of failure to interrupt or prevent repetitions.

Q: Has the Company concluded that its proposed penalties *are* sufficient?

A: No. The Company does not believe that it can evaluate the sufficiency of the penalties.

> …BGE cannot determine whether a customer will make an economic choice to pay these charges in lieu of incurring losses in their business by interrupting their operations. (DR MIG 1-3 Supplement)

Q: Is this a reasonable perspective?

A: No. The Company is correct that it cannot determine whether Schedule IS customers will find it economically advantageous to interrupt, but that is not the purpose of designing non-compliance penalties. Those penalties should

- compensate other customers for the costs incurred by the Schedule IS customer's failure to comply with its obligations.
- ensure that customers who do not really expect to be able to interrupt will choose the firm rate, allowing BGE to plan for their loads.

Estimating the costs of non-compliance is difficult, and I will not attempt to address the first point. However, it is relatively straightforward to determine whether the penalties are large enough so that a customer cannot expect to profit from the interruptible rate unless it intends to comply with notices of interruption. From the perspective of Company planning, the worst outcome is to have load on interruptible rates, and hence not included in the Company's investment decisions, that turns out to be non-interruptible. If the nominally interruptible customer fails to interrupt, it should wind up paying more, not less, than it would have paid as a firm customer.

Q: Can you provide an illustrative example of the effect of the penalty charges on the bills of a customer on Schedule IS?

A: Yes. I have evaluated the effect of the penalty charges on the twelve monthly bills of a hypothetical Schedule IS customer who makes unauthorized use of BGE gas during a year's single, five-hour interruption. This customer has an average daily load of 500 Dth/day and a billing demand of 1,000 Dth/day. Exhibit PLC-5 compares the annual bill under current and proposed rates of this customer under Schedule IS to its bill as a Schedule C delivery customer. My calculation of the IS customer's bill is based on the Company's calculation in DR OPC 6-26. As Exhibit PLC-5 shows, the interruptible customer has a significantly lower bill than the Schedule C customer, even though it did not comply with the Company's interruption notice.

The effect of the Schedule IS penalties will depend on the duration and frequency of interruption and the size and load factor of the customer.

Q: How should the non-compliance penalties in Schedules IS and AIS be designed?

A: Schedules AIS and IS penalties should be designed so that customers that fail to comply with notices to interrupt will pay more than the firm Schedule C customers for their annual sendout. The Commission should require the Company to demonstrate that few, if any, customers could reduce their bills by being non-complying interruptible customers, rather than being on the applicable firm tariff. Since the effect of the Schedule IS penalties will depend on the duration and frequency of interruption and the size and load factor of the customer, this demonstration should cover a range of characteristics of load and interruptions.

Q: What is the effect of imposing a large portion of the penalty for failure to interrupt in the form of an increase in the demand rate?

A: While that penalty creates a sizable incentive to avoid failure to reduce load below 10 Dth for more than three hours (the definition of a failure to interrupt) when requested, it does not provide any incentive to

- reduce the amount of gas taken during the failure to interrupt,
- reduce the duration of the failure to interrupt,
- avoid additional failures to interrupt later in the same billing month.

Under current rates, once a customer has triggered the failure-to-interrupt provisions, its demand charge would grow from $2.41/Dth-day to $5.80 for the next 12 months, regardless of the number or length of failures or the amount of gas delivered during the failures to interrupt. It is not an incremental charge that is added on for each failure.

Indeed, the demand-rate penalty provides little incentive to avoid failures in subsequent months within a winter. If a customer fails to interrupt in December 2005, it apparently would pay the higher demand charge for December 2005 through November 2006, resulting in a penalty for the

December 2005 penalties of $3.39 times its billing demand applied in each of the twelve months. For a customer with a billing demand of 1,000 Dth/day, that would be a penalty of $40,680. If the customer also fails to interrupt in January 2006, the demand-rate penalty would only be extended one month, to include December 2006, resulting in a penalty of only $3,390 for the second violation.

The Company, in addition to designing Schedule IS so that customers who are unlikely to interrupt will switch to Schedule C, should redesign the demand-price penalty to give better incentives. For example, a penalty of as much as $40 per Dth taken during an interruption by the customer described above (with a billing demand of 1,000 Dth/day) would—compared to the Company's approach—charge that customer less for failing to interrupt

- for a day at 1,000 Dth
- for two days in the same month at 500 Dth each
- for two days in subsequent months at 500 Dth each

But it would charge the customer more than the Company design for failing to interrupt

- for two days in the same month at 1,000 Dth each
- for two days in subsequent months at 1,000 Dth each

It would also give the customer an incentive to avoid and shorten every interruption, and to reduce gas taken in every interruption.

Q: Is there any reason to suppose that failure of IS customers to interrupt might increase in the future?

A: Yes. The Company projects that distribution system interruptions will occur more frequently as firm service customers are added and distribution capacity becomes more constrained. (Duhan Direct Testimony, page 33). In addition, the

Company's proposal to eliminate the requirement that Schedule IS customers maintain alternative fuel capability may result in increased non-compliance.

Q: What is the Company's basis for eliminating this alternative-fuel-capability requirement?

A: The Company claims that it is inefficient to require customers to maintain this equipment.

Q: Why might eliminating the alternative fuel requirement increase un-authorized use by interruptible customers?

A: Avoiding investment in alternative fuel capability reduces the cost to that customer of going on an interruptible rate, yet increases the cost to the customer of interruption. As long as the IS penalty charges are too low, eliminating the requirement for alternative-fuel capability is likely to attract more customers to the IS rate with reduced incentives to comply with an interruption request.

C. Elimination of the Gas Air Conditioning Rider

Q: What is BGE's proposal for the Gas Air Conditioning rate, Rider 5?

A: The Company proposes to eliminate Rider 5.

Q: What is BGE's rationale for eliminating Rider 5?

A: In BGE's view, since only four customers have taken advantage of this special rate, retaining it is a waste of Company and PSC resources.

Q: What is your response to the Company's proposal?

A: The cost of maintaining a gas-cooling rate seems small compared to the potential benefits. Use of gas for air-conditioning increases gas use at an off-peak time, when gas delivery costs are relatively low. Gas load for cooling is often lower than for heating, even for the gas-cooling building, and almost always for the area surrounding that building, so even local delivery costs tend to be very small. The gas cooling reduces electric use at the times when electric energy costs are greatest and most volatile, and line losses are highest; even small load increases can lead to price spikes, and loads determine requirements for generation, transmission, and generation capacity. Gas cooling and dehumidification should be encouraged. The technology may gain acceptance in the future, especially if peak-period electric prices continue to rise.

D. Service Upgrade Charges for Residential Customers

Q: What change does BGE propose in service upgrade charges?

A: Under current provisions, BGE will provide a residential service upgrade at its own expense. Under BGE's proposal, it would distinguish between what BGE calls "standard" gas applications—space heating, cooking, water heating and clothes drying—and "nonstandard" applications, such as pool heaters or electric generators. For "standard" applications, the Company would continue to pay for the upgrade. If the increase in load is due to a "nonstandard" applications the customer would pay an extension charge as if it were taking new service (Duhan Testimony at 27).

Q: What is BGE's rationale for introducing these residential extension charges?

A: In BGE's view, the extension charges are necessary to recover the costs of serving "intermittent or discretionary" uses:

> Unlike standard applications such as gas furnaces, gas water heaters and gas stoves, which typically have a consistent utilization for basic living, BGE has determined that non-standard gas applications have inconsistent operation and, therefore, would provide minimal incremental revenues to recover the cost of the service upgrade. With limited annual gas use, "non-standard" gas applications clearly do not generate revenues sufficient to provide a fair return for the upgrade under current Tariff provisions, but the proposed change will improve this situation. (DR OPC 6-54)

Q: How has the Company "determined that non-standard gas applications have inconsistent operation and...would provide minimal incremental revenues," and that they "clearly do not generate revenues sufficient to provide a fair return for the upgrade"?

A: The Company has not offered any analysis to support its proposal. The Company has not performed any economic tests of residential "non-standard" uses or even identified the non-standard applications it has in mind (other than pool heaters and generators):

> BGE did not perform a formal study related to the revenues generated from residential "non-standard" gas applications; rather the Company looked at their typical hours of utilization. (DR OPC 6-54)

It is not clear how the Company determined the typical hours of utilization of broad ranges of identified applications (generators and pool heaters), let alone the typical hours of utilization of unspecified "non-standard" applications.

Q: What's wrong with Company's argument?

A: The purpose of assessing line-extension charges is to limit the extent to which BGE invests in new service lines for loads that will not cover the cost of the line, increasing costs to other customers. Whether a new load pays for its service drop depends on the amount of gas used by the load and the shape of the load, particularly its distribution between summer and winter, as well as the load's tendency to follow system load, exacerbating peaks. End-use would only be a reasonable way of determining whether line extension charges should be applied if particular end uses were likely not to cover the costs of the service lines added to serve them. Otherwise, the Company would simply be discriminating against particular end uses.

The two end-uses the Company has identified as non-standard cover wide ranges of annual sales and load shapes. For example, an electric generator in a residential building may be a back-up generator, running only for an hour a month for testing purposes and for a few days after hurricanes and other power disruptions. That additional sales to that generator are not likely to pay for a larger service line to the customer. But another electric generator could be part of a combined-heat-and-power application, supplying hot water and space heat. The sales to that generator would probably be greater than for an increased heating load that required the same size service, and more of the gas would be delivered at low-load periods, yet the Company proposes to charge a line-extension fee for the combined-heat-and-power system and not for the incremental heating load.

Similarly, a pool heater can be used to heat an indoor pool in the winter, an outdoor pool in the spring and fall, or some other load shape. Some of these loads may be produce more revenue and less distribution cost than heating loads, yet BGE would still impose a line-extension charge.

Q: If the Commission agrees to allow some residential upgrade charges, what extension policy do you recommend?

A: Any charges for upgrades to residential services should be based on the shape of the added load, not on arbitrary end-use classifications. It is generally reasonable that a customer who requires an upgrade to accommodate a low-load-factor and intermittent use, such as a back-up generator, should pay for a portion of that upgrade. Upgrade charges should not be assessed if either of the following conditions apply:

- The additional revenues, net of allocated mains and supply costs, exceeds the net revenues for a space-heating conversion that would use a similar service line.[11]
- The additional load serves a special need for a residential customer who would be unduly burdened by the charge. A middle-class household may be financially constrained enough by the costs of an emergency generator and other medical equipment for an ailing family member, without additional charges for the service upgrade.

Q: Does this conclude your testimony?

A: Yes.

[11]The supply costs in this computation should be the supply costs in base rates allocated to residential, per MMBtu/day of CP load, plus any difference between the cost of gas to supply the load and the revenues in the Gas Commodity Price rider.

Exhibit PLC-1

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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)

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Sigma Xi (Research)

Institute Award, Institute of Public Utilities, 1981.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

PRESENTATIONS

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

“Accounting for Externalities: Why, Which and How?” Understanding Massachusetts’ New Integrated Resource Management Rules; Needham, Massachusetts, November 9 1990.

“Increasing Market Share Through Energy Efficiency.” New England Gas Association Gas Utility Managers’ Conference; Woodstock, Vermont, September 10 1990.

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

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

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

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

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

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

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

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

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

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

ADVISORY ASSIGNMENTS TO REGULATORY COMMISSIONS

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

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

EXPERT TESTIMONY

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

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

2. **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.

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

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

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

6. **ASLB, NRC** 50-471; Pilgrim Unit 2, Boston Edison Company; Commonwealth of Massachusetts; June 29 1979.

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

7. **MDPU** 19845; Boston Edison Time-of-Use Rate Case; Massachusetts Attorney General; December 4 1979.

   Critique of utility marginal cost study and proposed rates; principles of marginal cost principles, cost derivation, and rate design; options for reconciling costs and revenues. Joint testimony with S.C. Geller. Testimony eventually withdrawn due to delay in case.

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

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

9. **MDPU** 20248; Petition of MMWEC to Purchase Additional Share of Seabrook Nuclear Plant; Massachusetts Attorney General; June 2 1980.

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

10. **MDPU** 200; Massachusetts Electric Company Rate Case; Massachusetts Attorney General; June 16 1980.

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

11. **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.

112.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.

113. **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.

114. **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.

115. **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.

116. **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.

117. **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.

118. **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.

119. **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.

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

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

121. **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.

122. **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.

123. **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."

124. **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.

125. **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.

126. **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.

127. **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.

128. **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.

129. **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.

130. **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.

131. **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.

132. **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.

133. **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.

134. **North Carolina Utilities Commission** E-2, Sub 669. December 1995.

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

135. **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.

136. **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.

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

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

138. **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.

138 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.

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

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

140. **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.

141. **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.

142. **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.

143. **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.

144. **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.

145. **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.

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

Performance incentives proposed for the Boston Edison company.

147. **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.

148. **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.

149. **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.

150. **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.

151. **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.

152. **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.

153. **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.

154. **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.

155. **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.

156. **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.

157. **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.

158. **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.

159. **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.

160. **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.

161. **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.

162. **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.

163. **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.

164. **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

165. **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.

166. **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.

167. **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.

168. **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.

169. **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.

170. **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.

171. **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.

172. **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.

173. **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.

174. **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.

175. **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.

176. **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.

177. **MEFSB** 97-4; MMWEC gas-pipeline proposal; Town of Wilbraham, Mass. June 2000.

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

178. **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.

179. **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.

180. **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.

181. **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.

182. **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.

183. **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.

184. **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.

185. **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.

186. **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.

188. **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.

187. **MDTE** 01-56, Berkshire Gas Company; Massachusetts Attorney General. October 2001.

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

188. **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.

189. **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.

190. **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.

191. **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.

192. **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.

194. **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.

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

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

196. **NY PSC** Cases 03-G-1671 & 03-S-1672; Consolidated Edison Company Steam and Gas Rates; City of New York. Direct June 2003; 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.

197. **New Jersey BPU** ER02080507; Jersey Central Power & Light rates; N.J. Division of the Ratepayer Advocate. Phase I December 2002; Phase II July 2003.

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

198. **Connecticut DPUC** 03-07-02; CL&P rates; AARP. September 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.

199. **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..

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. **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.

203. **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.

204. **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.

Exhibit PLC-2: OPC Proposed Allocation of Requested Rate Increase

	Revenue at Current Rates[a]	BG&E Proposal[a]	Increase	Revenue at 100% of System Average ROR[c]	Increase	OPC Proposal[d]	Increase	Difference BGE vs. OPC Revenue Allocation
Base Rate Revenues								
Schedule D	$186,840,786	$26,976,493	14.4%	$21,627,520	11.6%	$25,735,063	13.8%	$1,241,430
Schedule C	54,560,757	21,509,725	39.4%	25,552,259	46.8%	21,509,725	39.4%	
Schedule PLG	64,959	31,455	48.4%	96,464	148.5%	31,455	48.4%	
Schedule IS	10,706,753	2,487,202	23.2%	3,255,670	30.4%	3,255,670	30.4%	
Schedule AIS	1,242,008	279,300	22.5%	361,240	29.1%	361,240	29.1%	
ISG	4,828,194	1,025,307	21.2%	1,420,880	29.4%	1,420,880	29.4%	
TOTAL	$258,243,456	$52,309,483		$52,314,033		$52,314,033		
Total Bills								
Schedule D	$557,290,763	$26,976,493	4.8%	$21,627,520	3.9%	$25,735,063	4.6%	
Schedule C	323,743,528	21,509,725	6.6%	25,552,259	7.9%	21,509,725	6.6%	
Schedule PLG	197,512	31,455	15.9%	96,464	48.8%	31,455	15.9%	
Schedule IS	163,850,934	2,487,202	1.5%	3,255,670	2.0%	3,255,670	2.0%	
Schedule AIS	10,406,313	279,300	2.7%	361,240	3.5%	361,240	3.5%	
ISG	70,193,536	1,025,307	1.5%	1,420,880	2.0%	1,420,880	2.0%	
TOTAL	$1,125,682,586	$52,309,483		$52,314,033		$52,314,033		

NOTES:

[a] Source: Company Exhibit LHD-2 at Sheet G-2

[b] Source: DR OPC 5-43

[c] Schedules C and PLG as proposed by BG&E; difference moved onto Schedule D.

[d] Source: Company Exhibit LHD-2 at Sheet G-11

Exhibit PLC-3: Computation of 1997 Services Allocation

Schedule	Investment	New Growth	Investment w/o Additions	Retirements	Replacements
2002					
D	$27,339,214.00		$27,339,214.00	$1,048,883.11	$413,408.32
DH	$188,152,208.00	$4,209,377.99	$183,942,830.01	$7,057,061.96	$2,781,480.69
C	$2,962,154.00		$2,962,154.00	$113,644.57	$44,792.04
CH	$30,730,411.00	$1,370,600.97	$29,359,810.03	$1,126,404.32	$443,962.64
CL	$23,543,810.00		$23,543,810.00	$903,270.47	$356,016.34
AIS	$554,579.00		$554,579.00	$21,276.71	$8,386.03
IS	$1,300,164.00		$1,300,164.00	$49,881.47	$19,660.35
PLG	$32,806.00		$32,806.00	$1,258.62	$496.07
BS/ISG	$147,705.00		$147,705.00	$5,666.78	$2,233.51
Total	$274,763,051.00		$269,183,072.05	$10,327,348.00	$4,070,436.00
2001					
D	$27,974,688.79		$27,974,688.79	$1,307,381.47	$682,850.75
DH	$188,218,411.28	$6,762,290.27	$181,456,121.01	$8,480,250.55	$4,429,269.92
C	$3,031,006.54		$3,031,006.54	$141,652.40	$73,985.63
CH	$30,042,251.71	$2,071,150.89	$27,971,100.83	$1,307,213.79	$682,763.17
CL	$24,091,064.13		$24,091,064.13	$1,125,882.44	$588,053.05
AIS	$567,469.68		$567,469.68	$26,520.38	$13,851.70
IS	$1,330,385.11		$1,330,385.11	$62,174.81	$32,474.16
PLG	$33,568.55		$33,568.55	$1,568.81	$819.39
BS/ISG	$151,138.27		$151,138.27	$7,063.36	$3,689.22
Total	$275,439,984.05		$266,606,542.89	$12,459,708.00	$6,507,757.00
2000					
D	$28,599,219.51		$28,599,219.51	$1,835,213.95	$721,395.28
DH	$185,507,101.64	$7,198,049.63	$178,309,052.01	$11,442,104.52	$4,497,720.97
C	$3,098,673.30		$3,098,673.30	$198,842.09	$78,161.86
CH	$28,595,551.45	$2,335,302.63	$26,260,248.82	$1,685,122.03	$662,396.39
CL	$24,628,893.51		$24,628,893.51	$1,580,437.84	$621,246.59
AIS	$580,138.35		$580,138.35	$37,227.52	$14,633.58
IS	$1,360,085.76		$1,360,085.76	$87,276.80	$34,307.21
PLG	$34,317.96		$34,317.96	$2,202.19	$865.65
BS/ISG	$154,512.41		$154,512.41	$9,915.07	$3,897.47
Total	$272,558,493.89		$263,025,141.63	$16,878,342.00	$6,634,625.00
1999					
D	$29,713,038.17		$29,713,038.17	$670,655.16	$873,035.93
DH	$185,253,435.57	$6,254,347.17	$178,999,088.40	$4,040,201.52	$5,259,396.03
C	$3,219,353.52		$3,219,353.52	$72,664.26	$94,591.85
CH	$27,282,974.46	$2,823,617.05	$24,459,357.41	$552,073.95	$718,670.96
CL	$25,588,084.77		$25,588,084.77	$577,550.53	$751,835.51
AIS	$602,732.29		$602,732.29	$13,604.31	$17,709.63
IS	$1,413,055.35		$1,413,055.35	$31,894.18	$41,518.75
PLG	$35,654.50		$35,654.50	$804.76	$1,047.61
BS/ISG	$160,530.01		$160,530.01	$3,623.33	$4,716.73
Total	$273,268,858.63	$9,077,964.22	$264,190,894.42	$5,963,072.00	$7,762,523.00
1998					
D	$29,510,657.41		$29,510,657.41	$342,765.05	$793,222.85
DH	$177,779,893.89	$5,683,062.53	$172,096,831.35	$1,998,897.48	$4,625,825.05
C	$3,197,425.93		$3,197,425.93	$37,137.97	$85,944.25
CH	$24,292,760.39	$4,325,119.94	$19,967,640.45	$231,923.31	$536,714.19
CL	$25,413,799.79		$25,413,799.79	$295,180.22	$683,102.59
AIS	$598,626.97		$598,626.97	$6,953.03	$16,090.61
IS	$1,403,430.78		$1,403,430.78	$16,300.79	$37,723.10
PLG	$35,411.65		$35,411.65	$411.30	$951.84
BS/ISG	$159,436.61		$159,436.61	$1,851.85	$4,285.53
Total	$262,391,443.42		$252,383,260.94	$2,931,421.00	$6,783,860.00
1997					
D	$29,060,199.61				
DH	$169,469,903.79				
C	$3,148,619.65				
CH	$19,662,849.57				
CL	$25,025,877.41				
AIS	$589,489.38				
IS	$1,382,008.47				
PLG	$34,871.12				
BS/ISG	$157,002.93				
Total	$248,530,821.94				

Exhibit PLC-4: Re-estimate of Service Allocation Changes, 1997–2003

Schedule	Investment	BG&E Discrepancy	New Growth	Retirements	Retirement Allocator	Conversions	Replacements	Replacement Allocator
2003								
D	$14,581,262.46	$7,919.39		$2,031,393.00	$1,154,166.66		$330,038.71	$13,003,628.42
DH	$197,181,113.12	$107,093.18	$2,558,292.22	$6,449,226.14	$3,664,225.36	$824,127.95	$3,664,225.36	$144,371,626.75
C	$3,040,924.48	$1,651.59		$119,821.63	$68,078.47		$68,078.47	$2,682,313.09
CH	$33,047,708.68	$17,948.90	$1,123,979.54	$748,275.42	$425,144.00		$425,144.00	$16,750,806.58
CL	$24,169,893.99	$13,127.17		$952,366.99	$541,101.71		$541,101.71	$21,319,576.82
AIS	$569,326.53	$309.21		$22,433.19	$12,745.76		$12,745.76	$502,186.76
IS	$1,348,953.67	$732.64	$14,207.61	$52,592.73	$29,881.36		$29,881.36	$1,177,334.78
PLG	$24,095.26	$13.09	-$9,577.92	$1,327.03	$753.97		$753.97	$29,706.75
BS/ISG	$151,632.82	$82.35		$5,974.79	$3,394.67		$3,394.67	$133,751.00
Totals	$274,114,911.00	$148,877.53	$3,686,901.45	$10,383,410.93	$5,899,491.95	$824,127.95	$5,075,364.00	$199,970,930.94
2002								
D	$16,274,697.37			$2,779,517.71	$1,386,455.47		$305,491.26	$15,783,146.13
DH	$196,476,600.54		$3,128,413.78	$5,828,251.91	$2,907,199.22	$1,080,964.21	$2,907,199.22	$150,199,878.66
C	$3,091,016.05			$108,284.41	$54,013.51		$54,013.51	$2,790,597.50
CH	$32,228,911.66		$1,370,600.97	$676,226.50	$337,309.57		$337,309.57	$17,427,033.08
CL	$24,568,032.10			$860,666.79	$429,310.51		$429,310.51	$22,180,243.61
AIS	$578,704.75			$20,273.17	$10,112.49		$10,112.49	$522,459.93
IS	$1,356,724.80			$47,528.75	$23,707.89		$23,707.89	$1,224,863.53
PLG	$34,233.15			$1,199.26	$598.20		$598.20	$30,906.00
BS/ISG	$154,130.58			$5,399.50	$2,693.33		$2,693.33	$139,150.50
Totals	$274,763,051.00		$4,499,014.75	$10,327,348.00	$5,151,400.21	$1,080,964.21	$4,070,436.00	$210,298,278.94
2001								
D	$18,748,723.82			$3,805,068.81	$2,609,580.42		$572,259.36	$19,588,214.94
DH	$195,188,275.24		$4,724,969.21	$6,682,902.96	$4,583,247.65	$2,037,321.06	$4,583,247.65	$156,882,781.61
C	$3,145,286.95			$124,163.16	$85,153.19		$85,153.19	$2,914,760.67
CH	$31,197,227.62		$2,071,150.89	$775,387.92	$531,774.12		$531,774.12	$18,202,421.00
CL	$24,999,388.37			$986,874.40	$676,815.12		$676,815.12	$23,167,118.01
AIS	$588,865.43			$23,246.02	$15,942.51		$15,942.51	$545,705.95
IS	$1,380,545.66			$54,498.34	$37,375.88		$37,375.88	$1,279,361.87
PLG	$34,834.21			$1,375.11	$943.08		$943.08	$32,281.12
BS/ISG	$156,836.75			$6,191.28	$4,246.08		$4,246.08	$145,341.78
Totals	$275,439,984.05		$6,796,120.09	$12,459,708.00	$8,545,078.06	$2,037,321.06	$6,507,757.00	$222,757,986.94
2000								
D	$21,981,533.27			$6,383,788.50	$3,598,406.84		$719,066.70	$25,972,003.44
DH	$190,525,640.28		$4,318,709.49	$8,103,640.26	$4,567,850.98	$2,879,340.14	$4,567,850.98	$164,986,421.88
C	$3,184,296.92			$150,559.36	$84,867.14		$84,867.14	$3,065,320.03
CH	$29,369,690.53		$2,335,302.63	$940,229.83	$529,987.71		$529,987.71	$19,142,650.83
CL	$25,309,447.65			$1,196,676.83	$674,541.47		$674,541.47	$24,363,794.85
AIS	$596,168.94			$28,187.95	$15,888.95		$15,888.95	$573,893.90
IS	$1,397,668.12			$66,084.30	$37,250.32		$37,250.32	$1,345,446.17
PLG	$35,266.24			$1,667.45	$939.91		$939.91	$33,948.57
BS/ISG	$158,781.95			$7,507.50	$4,231.82		$4,231.82	$152,849.28
Totals	$272,558,493.89		$6,654,012.12	$16,878,342.00	$9,513,965.14	$2,879,340.14	$6,634,625.00	$239,636,328.94
1999								
D	$27,646,255.08							
DH	$186,863,379.94			$1,902,972.69	$3,225,363.36		$881,028.79	$27,874,976.13
C	$3,249,989.15		$3,910,012.60	$3,135,110.44	$5,313,723.31	$2,344,334.57	$5,313,723.31	$168,121,532.32
CH	$27,444,630.02			$58,247.93	$98,724.87		$98,724.87	$3,123,567.96
CL	$25,831,583.01		$2,823,617.05	$363,753.11	$616,528.01		$616,528.01	$19,506,403.94
AIS	$608,467.94			$462,966.51	$784,685.57		$784,685.57	$24,826,761.36
IS	$1,426,502.10			$10,905.27	$18,483.42		$18,483.42	$584,799.17
PLG	$35,993.79			$25,566.48	$43,332.83		$43,332.83	$1,371,012.65
BS/ISG	$162,057.63			$645.10	$1,093.38		$1,093.38	$34,593.67
Totals	$273,268,858.63			$2,904.48	$4,922.82		$4,922.82	$155,753.75
			$6,733,629.65	$5,963,072.00	$10,106,857.57	$2,344,334.57	$7,762,523.00	$245,599,400.94
1998								
D	$28,668,198.98			$1,185,223.48	$4,066,117.21		$793,222.85	$29,060,199.61
DH	$178,430,419.90		$2,410,168.17	$1,348,371.47	$4,625,825.05	$3,272,894.37	$4,625,825.05	$169,469,903.79
C	$3,209,512.20			$25,051.70	$85,944.25		$85,944.25	$3,148,619.65
CH	$24,368,238.07		$4,325,119.94	$156,445.63	$536,714.19		$536,714.19	$19,662,849.57
CL	$25,509,863.95			$199,116.06	$683,102.59		$683,102.59	$25,025,877.41
AIS	$600,889.78			$4,690.22	$16,090.61		$16,090.61	$589,489.38
IS	$1,408,735.75			$10,995.82	$37,723.10		$37,723.10	$1,382,008.47
PLG	$35,545.50			$277.45	$951.84		$951.84	$34,871.12
BS/ISG	$160,039.28			$1,249.18	$4,285.53		$4,285.53	$157,002.93
Totals	$262,391,443.42		$6,735,288.11	$2,931,421.00	$10,056,754.37	$3,272,894.37	$6,783,860.00	$248,530,821.94
1997								
D	$29,060,199.61							
DH	$169,469,903.79							
C	$3,148,619.65							
CH	$19,662,849.57							
CL	$25,025,877.41							
AIS	$589,489.38							
IS	$1,382,008.47							
PLG	$34,871.12							
BS/ISG	$157,002.93							
Totals	$248,530,821.94							

Exhibit PLC-5:
Comparision of Bills for Non-Complying Interruptible Customer vs. Firm Commercial Customer

Effect of Penalty Charges in the Current Schedule IS
Duration of interruption: 5 hours

	Annual Bill at Current Rates of Schedule IS Customer who Uses BG&E Gas During an Interruption				Annual Bill at Current Rates of Schedule C Delivery Customer		
	Billing Determinants	*Rates*	*Revenues*		*Billing Determinants*	*Rates*	*Revenues*
	Bills				Bills		
1 CUSTOMER CHARGE	12	$1,500	$18,000		12	$27	$324
2 INFORMATION FEE	12	$65	$780		12	$65	$780
3 DEMAND CHARGE	DTH / DAY						
Billing demand (1,000 Dth/day for 12 months)	12,000	$5.80	$69,600				
4 DELIVERY CHARGE	THERMS	$/TH			THERMS	$/TH	
Critical Use Gas Supplied by BG&E	110	$0.60	$66	First 10,000 therms per mo	120,000	$0.1736	$20,832
Excess of Critical Use Gas during interruption	1,390	$1.60	$2,224	All Over	1,680,000	$0.0948	$159,264
Annual delivered gas (excl BGE gas used)	1,798,500	$0.0236	$42,445	Total	1,800,000		
Total Annual Use @ 150,000 therms/month	1,800,000						
5 TOTAL REVENUE			$133,115				$181,200

Assumptions:
See DR OPC 6-26
Delivery Service rate includes the Comprehensive Balancing Service Price of 0.12 cents per therm
Cost of Critical Use Gas: $0.6 is assumed to be the difference between the Production Rate, $1.20 per therm, and the firm customer's delivered gas cost.

Exhibit PLC-5:
Comparision of Bills for Non-Complying Interruptible Customer vs. Firm Commercial Customer

Effect of Penalty Charges in BG&E's Proposed Schedule IS
Duration of interruption: 5 hours

	Annual Bill at Proposed Rates of Schedule IS Customer who Uses BG&E Gas During an Interruption				**Annual Bill at Current Rates of Schedule C Delivery Customer**		
	Billing Determinants	*Rates*	*Revenues*		*Billing Determinants*	*Rates*	*Revenues*
	Bills				Bills		
1 CUSTOMER CHARGE	12	$1,500	$18,000		12	$35	$420
2 INFORMATION FEE	12	$65	$780		12	$65	$780
3 DEMAND CHARGE	DTH / DAY						
Billing demand (1,000 Dth/day for 12 months)	12,000	$7.42	$89,040				
Total							
4 DELIVERY CHARGE	THERMS	$/TH			THERMS	$/TH	
Critical Use Gas Supplied by BG&E	110	$0.60	$66	First 10,000 therms per mo	120,000	$0.2102	$25,224
Excess of Critical Use Gas during interruption	1,390	$1.60	$2,224	All Over	1,680,000	$0.1148	$192,864
Annual delivered gas (excl BGE gas used)	1,798,500	$0.0304	$54,674	Total	1,800,000		
Total Annual Use @ 150,000 therms/month	1,800,000						
5 TOTAL REVENUE			$164,784				$219,288

Assumptions:
See DR OPC 6-26
Delivery Service rate includes the Comprehensive Balancing Service Price of 0.12 cents per therm
Cost of Critical Use Gas: $0.6 is assumed to be the difference between the Production Rate, $1.20 per therm, and the firm customer's delivered gas cost.