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INDIANA UTILITY REGULATORY COMMISSION

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INDIANA UTILITY REGULATORY COMMISSION

VERIFIED PETITION OF INDIANA GAS COMPANY, INC. AND SOUTHERN INDIANA GAS AND ELECTRIC COMPANY D/B/A VECTREN ENERGY DELIVERY OF INDIANA, INC. FOR APPROVAL OF A CONSERVATION PROGRAM AND A CONSERVATION ADJUSTMENT THROUGH APPROVAL OF NEW TARIFF RIDERS AND ASSOCIATED TERMS AND CONDITIONS OF SERVICE UNDER IND. CODE § 8-1-2-42(a)	)	Cause No. 42943
VERIFIED PETITION OF INDIANA GAS COMPANY, INC. AND SOUTHERN INDIANA GAS AND ELECTRIC COMPANY, BOTH D/B/A VECTREN ENERGY DELIVERY OF INDIANA, INC., FOR APPROVAL OF AN ALTERNATIVE REGULATORY PLAN PURSUANT TO IND. CODE § 8-1-2.5-6 PROVIDING FOR: (A) A TWO PHASE GAS SERVICE ENERGY EFFICIENCY PROGRAM FOR THE RESIDENTIAL AND GENERAL SERVICE CUSTOMER CLASSES; (B) AN ENERGY EFFICIENCY RIDER TO THEIR GAS TARIFFS THAT WILL RECOVER THE COST OF THE ENERGY EFFICIENCY PROGRAM AND PETITIONERS' AUTHORIZED MARGINS IRRESPECTIVE OF CHANGES IN CUSTOMER USAGE; AND (C) A RETURN ON EQUITY EARNINGS TEST TO BE IMPLEMENTED IN LIEU OF THE NET OPERATING INCOME EARNINGS TEST CURRENTLY USED IN THEIR GAS COST ADJUSTMENT PROCEEDINGS	)	Cause No. 43046

Submittal of Pre-Filed Testimony of Grant Smith and Paul Chernick

Citizens Action Coalition of Indiana, Inc., by counsel, respectfully submits the attached testimony on Behalf of the Citizens Action Coalition of Indiana.

Submitted by,

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DIRECT TESTIMONY OF

PAUL CHERNICK

ON BEHALF OF

CITIZENS ACTION COALITION

RESOURCE INSIGHT, INC.

JUNE 26, 2006

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I. Introduction and Qualifications

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

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

Q: Summarize your professional education and experience.

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

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

My work has considered, among other things, the cost-effectiveness of prospective new generation plants and transmission lines, retrospective review of generation-planning decisions, ratemaking for plant under construction, ratemaking for excess and/or uneconomical plant entering service, conservation program design, cost recovery for utility efficiency programs, the valuation of environmental externalities from energy production and use, allocation of costs of service between rate classes and jurisdictions, design of retail and wholesale rates, and performance-based ratemaking and cost recovery in restructured gas and electric industries. My professional qualifications are further detailed in CAC Exhibit No. PLC-1.

Q: Have you testified previously in utility proceedings?

A: Yes. I have testified approximately two hundred times on utility issues before various regulatory, legislative, and judicial bodies in the United States and Canada.

Q: Have you testified previously on utility recovery of the costs and lost revenues associated with DSM programs?

A: Yes. A number of such testimonies are listed in my qualifications. I have supported decoupling in some cases (e.g., in Ontario), and opposed decoupling in other situations (e.g., for Con Edison's electric sales). In addition, I have worked on issues of cost recovery and lost revenues in collaborative efforts among utilities, consumer advocates, and other parties.

II. Introduction

Q: On whose behalf are you testifying?

A: My testimony is sponsored by the Citizens Action Coalition.

Q: What is the purpose of your direct testimony?

A: The Citizens Action Coalition has asked me to review a number of the issues raised by the settlement agreement filed by Vectren and the Indiana Office of Utility Consumer Counselor, including the following questions:

- Whether the settlement proposal adequately links together Vectren's energy efficiency programs and the decoupling mechanism in the Sales Reconciliation Component (SRC).
- Whether the SRC appropriately balances ratepayer and shareholder interests.

Q: Do you agree with any portions of the settlement agreement?

A: Yes. I support many aspects of the settlement agreement, including

- utility sponsorship of energy efficiency programs
- recovery by the utility of prudently-incurred costs of such programs
- the creation of a multi-party Oversight Board to select a third-party administrator for the energy efficiency programs and to determine program structure and funding levels
- continuing evaluation of program effects
- recovery by the utility of the revenues lost due to its energy efficiency programs

Q: What aspects of the settlement should the Commission revise?

A: The Commission, if it approves the SRC, should clearly condition the continuation of the SRC to the continuation of the energy-efficiency programs.

The Commission should also require that the SRC formula be amended to minimize the extent to which it raises rates in response to the following:

- continuing trends in customer size or usage that would occur irrespective of the Efficiency Program,
- economic downturns, protecting Vectren shareholders at the expense of ratepayers,
- changes in average customer usage due to changes in metering or in the mix of new customers.

III. General Cautions on Decoupling Design

Q: Is the design of a decoupling mechanism simple and straightforward?

A: No. Decoupling is both a potent antidote to utility incentives to resist energy efficiency and a significant departure from traditional regulation. As such, decoupling can have serious side effects. Like any departure from standard practice, decoupling can upset the established balance of benefits, producing unanticipated windfalls and burdens. For all these reasons, decoupling must be applied with great care

Q: **Can the Commission set a general direction for decoupling policy, and refine the computation when Vectren files its claims for SRC adjustments?**

A: No. That approach works well in some situations. For example, the Commission can set the standards for the design and scope of the energy-efficiency portfolio, and refine the standards when it reviews specific proposals. Similarly, were the Commission approving the recovery of lost revenues from the energy-efficiency program, it could leave until later the formulas and methods to be used in estimating lost revenues. This incremental policymaking has the advantage that the Commission can concentrate on matters of real dispute, and weigh the considerations in light of actual numbers, rather than dealing with abstractions and possibilities.

Incremental decision making does not work for decoupling, since the method must be defined in advance in all its details. Certainly, Vectren's proposal would give the Commission no leeway for correcting errors retrospectively. The Commission can change the formula going forward, but the proposal leaves no room for retrospective adjustments.

Hence, setting up the system can be complex, and must be done with care.

Q: **What sorts of problems can arise from poorly designed decoupling?**

A: There are two basic groups of problems. The first has to do with establishing a system that brings the utility's margin back to the level that it would have expected without the energy-efficiency program. Decoupling might adjust the target margin to reflect changes in number of customers, trends in usage per customer, and/or indices of costs.[1] If those adjustments are poorly designed, the decoupling mechanism may increase the utility's margin when it would normally have been decreasing, or vice versa. In some situations, changes in margin from the value that would have occurred without decoupling or the efficiency program are acceptable (or even advantageous). In other situations, choosing the wrong index or adjustment may result in margins that are consistently inflated, or in rates rising at inappropriate times.

Q: What is the second group of problems with poorly designed decoupling?

A: Decoupling can entail such unintended consequences as the following:

- Reducing the utility's incentive to promote economic development and the cost-effective use of its product, as opposed to other fuels;
- Flowing through to ratepayers all the effects of fluctuations in the economy;
- Flowing through to ratepayers all the effects of changes in sales, from all causes, including changes in customer operating patterns, natural efficiency trends, replacement of older equipment with new equipment that meets higher efficiency standards, and response to the prices of gas and other fuels.

In addition, if the target margin is indexed to the number of customers, decoupling may

- change utility incentives regarding the promotion of rate switching and remetering.
- give the utility windfalls if large customers are broken up into multiple small customers.
- expose ratepayers to risks related to the physical size and fuel-use choices of new customers.

[1]Cost indices are generally applied when decoupling is part of a rate plan, with the expectation that future rate cases (and the attendant rate increases to track costs) would be delayed.

A. Decoupling and Economic Conditions

Q: How might a decoupling mechanism be affected by a recession or other economic downturn?

A: An economic downturn would tend to reduce usage, as customers tighten their belts, commercial vacancy rates rise, and hours of operation are reduced. The reduced usage would result in a decline in the actual margin, compared to the target margin (which is called the "order-granted margin" in the proposed SRC). Unless some fix is designed into the decoupling mechanism, the margin shortfall would allow the utility to raise rates.

Q: Would that outcome be desirable?

A: No. Raising rates during a recession would be most undesirable. Some rate increases may be essential in a downturn, to keep the utility financially sound. A rate case should be sufficient for that purpose. Almost every business and government unit, and many households, will experience some pain in a serious downturn. Letting the utility recover all its revenues lost to the recession would exempt it from sharing any of the pain resulting from the downturn.

Q: Have similar problems arisen with previous decoupling mechanisms?

A: Yes. In the early 1990s the Maine PUC established a rate adjustment mechanism for Central Maine Power that trued-up costs (other than fuel and purchased power) to a per-customer revenue target. Shortly after the plan was put in place, the regional economy took a turn for the worse, resulting in decreased sales. Sales fell and the decoupling mechanism would have raised CMP's rates by $52 million, as businesses and households were least prepared to pay the higher rates. As a result, the Maine Commission accepted a contested stipulation endorsed by the Public Advocate and industrial customers to terminate the rate adjustment mechanism prior to any rate change. The following year CMP requested a $87 million increase in rates and ultimately was awarded $35 million under conventional ratemaking principles. Since that 1994 rate case, CMP's performance-based Alternative Rate Plan has omitted any revenue-decoupling element.

Q: How can this problem be solved?

A: I can think of at least three approaches:

- The target margin can be indexed to the economy.
- An automatic circuit breaker can be defined that would terminate or limit the decoupling mechanism if certain economic markers are triggered.
- The Commission could implement a softer circuit-breaker, in the form of a provision that would allow the Commission on its own motion or any party meeting the statutory requirements to petition for reopening of the decoupling mechanism in the event of an economic downturn.

The last approach has the advantage of not requiring specific prior definition of the critical measures of the economy but has the disadvantage of placing the burden of proof on ratepayers or the Commission.

B. Changes in Metering

Q: How could changes in metering affect the customer-indexed decoupling?

A: Some decoupling mechanisms, including the SRC, increase the target margin by the product of some historical average margin per customer times the number of new customers since the base target margin was established.

Hence, if a building or facility currently metered as a single customer is remetered so that it is billed through multiple meters on separate accounts, Vectren's customer count would increase, without any significant cost to Vectren. Such remetering can occur when a master-metered apartment building is converted to individual meters for each apartment, a building occupied by a single large tenant is broken up to house numerous smaller tenants, or a master-metered commercial building with many tenants is converted so each business has its own meter. For each of these additional gas customers, the proposed SRC would increase the adjusted Order Granted Margin by the average margin for the existing customers. Of course, the major effect of these changes is to remove one large customer (or reduce its size) and replace it with many small customers.

Q: Could Vectren encourage such metering conversions?

A: Yes. Vectren could encourage conversions, by explaining the benefits to building owners. In fact, converting master-metered properties for single metering may have important conservation effects, by giving each tenant the incentive to reduce its gas use and bill. The reduction in tenant usage from the improved price signals would represent a loss of margin for Vectren, for which the SRC should compensate. However, the increase in the number of nominal customers and the resulting decrease in the average usage per customer is neither a reduction in usage nor a reduction in margin.[2] The SRC should not be increased by the number of new customers.

Q: How might the SRC be amended to eliminate this problem?

A: The SRC formula could be revised to explicitly exclude any change in customer number due to remetering. Alternatively, Vectren could be required to track any conversions of master meters to single-customer meters and report to the Oversight Board; if those figures are significant, the Board would have the responsibility to propose a correction to assure that the margin adjustment does not include replacement of master metering.

[2]Margin may actually increase with many small customers replacing one large customer.

C. Size of New Customers

Q: How could changes in the size of new customers affect the operation of a decoupling mechanism?

A: The new residential customers could be large single-family homes, or small condos or apartments. For any of these customers, the proposed SRC would increase the order-granted margin by the same average margin per residential customer. Similarly, new commercial customers could be small offices or stores using a few thousand therms per year, or much larger buildings using hundreds of thousands of therms. Each new commercial customer would similarly increase the SRC by the average order-granted margin for general-service customers.

Q: Is this simplification inherently unfair or biased?

A: Not so long as the mix of customer types and sizes remains fairly consistent over time. If new customers are much smaller (or larger) than the average existing customer, the SRC will provide Vectren with higher (or lower) revenues than Vectren would have received without the efficiency program or the SRC.

Q: How can this problem be avoided?

A: While some mechanical mechanism could be created to ensure that changes in the size of new customers does not bias the SRC, an early-warning system with provisions for mid-course corrections would probably suffice. For example, the Commission could require that Vectren annually provide the Parties with data from builders in its territory showing the size of new construction and the estimated gas usage and associated margins. If the new-customer estimated margin declines significantly from the average order-granted margin per customer, the Oversight

Board or any party could propose an adjustment to the accounting for new customer growth to reflect the smaller margins.[3]

Q: How could a similar problem be avoided for Vectren's Indiana gas operations?

A: Several approaches could be taken. First, the Commission could require Vectren to develop an explicit adjustment to the order-granted margin to reflect changes in important economic indicators, such as statewide unemployment rates. Second, adjusting margin per customer for changes in sales by Midwestern gas utilities without significant energy-efficiency programs (as I suggest in §V.A, below) would adjust margin for the affects of most major economic events. Third, the Commission could simply provide that any party may petition for modification of the SCR, in the event of a major economic downturn, and then leave to the parties the decision as to what events warrant reopening the SRC formula.

The important point is that the SRC be designed to leave Vectren as well off as it would have been without either the efficiency program or the SRC. The SRC should not become a broad defense for shareholders, diverting all manner of adverse outcomes onto ratepayers.

IV. Decoupling and Energy Efficiency

A. Linkage between Decoupling and Energy Efficiency

Q: What should be the connection between decoupling and energy efficiency?

A: Decoupling of the utility's earnings from sales should be seen as fundamentally related to the utility's commitment to effective energy-efficiency programs. The

[3] Any reduction in the average new-customer usage that is attributable to Vectren's energy-efficiency programs is a valid part of the SRC, and should not be eliminated.

purpose of decoupling is to allow the utility to pursue energy efficiency without suffering harm to shareholders; this point is made several times in the testimony of Vectren Witness Jerome Benkert, Jr..

Q: Is that connection clear in the settlement?

A: Not entirely. While decoupling is clearly consistent with Vectren funding and promoting energy efficiency, the settlement does not presume that the SRC would terminate if Vectren stopped funding substantial energy-efficiency programs.

Q: Do you propose that the Commission amend the settlement to require that the SRC automatically terminate if the energy-efficiency programs fall below some fixed level?

A: That requirement might be justified, to ensure that Vectren does not turn its back on energy efficiency. The SRC should certainly be terminated if the energy-efficiency program is completely eliminated. If the energy-efficiency program continues but only at a modest level of funding or effectiveness, the Commission should review the propriety of the SRC.

. For example, if Vectren's funding of energy efficiency for either of its gas companies falls below a substantial level, which I suggest be defined as 2% of bills for the customer classes eligible for the programs, Vectren should be required to show cause as to why the SRC should not be terminated. That showing should include a demonstration that the SRC is beneficial to ratepayers with little or no energy efficiency program. Between the reduction in the energy-efficiency budget and Commission's decision, Vectren should be allowed to compute the monthly incremental value of the SRC, but Vectren should only be eligible to recover that SRC balance if the Commission finds that such recovery is justified by the benefits to ratepayers.

B. Recovery of Lost Revenues from Energy-Efficiency Programs

Q: Would the settlement SRC provide for full recovery by Vectren of the revenue reductions due to Vectren's promotion of efficiency programs?

A: No. The settlement provides for recovery of 85% of the margin difference for Vectren North. Thus, while "the SRC moves closer to breaking the linkage between Vectren Energy's customer sales volumes and recovery of non-commodity costs" (Petitioner's Exhibit No. JAB-S2 at 18), it leaves Vectren with an unnecessary and unrecoverable loss in margin and earnings for every therm of additional efficiency achieved. Hence, Vectren would retain incentives to delay and decrease implementation of energy efficiency, and to steer programs away from measures that result in high revenue losses.

Q: Why did Vectren and OUCC reduce the SRC recovery by 15%?

A: According to Vectren, "The 15% offset represents a negotiated settlement term.... In recognition that...some level of reduced customer usage would occur irrespective of the Efficiency Program, the Parties agreed to reduce Vectren North's SRC recovery by this amount" (Benkert Settlement Testimony at 16–17).

Q: Is the 15% offset an appropriate response to the fact that some level of reduced customer usage would occur irrespective of the Efficiency Program?

A: No. The reduction in customer usage that would occur without of the Efficiency Program would not vary with the scale of the Efficiency Program. Hence, that background level of usage reduction should be built into the baseline for the SRC. Vectren should be allowed to recover 100% of the revenue lost due to reduction in sales below that modified baseline, and none of the revenue lost due to the continuing trends.

This alternative approach would leave Vectren no worse off with a larger or more-effective efficiency program, and no better off with a smaller or less-effective program. With the 15% SRC discount, Vectren would lose a little bit on every additional therm saved. I take this issue up again in §V.A, below.

V. Structural Problems with the Vectren Decoupling Proposal

Q: Other than the failure to link the SRC to continuation of the energy-efficiency program and to fully reflect the effects of efficiency program on Vectren's revenue, what problems have you identified in the SRC proposal?

A: The SRC proposal has the following problems I discussed in §III above:

- Vectren would be exempt from sharing the burden in an economic downturn.
- Remetering of large customers can increase bills for all customers.
- Addition of smaller customers can increase bills for all customers.

In addition, the SRC proposal has major flaws in its treatment of the trend in sales per customer, and in the proposal to recover 85% of the shortfall from the target margin. It is also important that rates be subject to review every few years, and that the decoupling plan not be left to run indefinitely without such review.

A. Trends in Sales per Customer

Q: Have Vectren's sales per customer been declining?

A: Yes. "Not only has usage continually declined every year for at least the last decade, but those declines have become potentially more sizeable as supply shortages have made market prices more volatile" (Testimony of Company Witness Benkert at 9).

CAC Exhibit No. PLC-2 shows actual and Vectren projections for delivery volumes, for the Vectren Indiana gas rate schedules that would be covered by the SRC. In that exhibit, I added computations of annual growth rates in annual usage per customer (AUPC) and in total volumes. If the AUPC growth is negative, the SRC would increase rates. That would be true, even if total volumes increase.

Even before the efficiency program, Vectren has experienced significant reductions in volumes and especially AUPC, and expects AUPC to continue falling for each rate schedule and company.

Q: Why might sales have been declining?

A: Recently, the high costs of gas commodity have probably been encouraging customers to turn down their thermostats, install more efficient windows and increased insulation, and generally make the types of investments the Efficiency Program will encourage. Since the declines have been continuous through periods of much lower commodity costs, the trends are probably also be driven by such factors as the following:

- Improvement in window efficiency and insulation levels as buildings are remodeled.
- Routine replacement of old and inefficient boilers, furnaces, and water heaters (as they fail) with new equipment that is more efficient due to efficiency standards and changes in normal practice.
- Addition of more-efficient new buildings to the average stock.
- Reduction in gas usage due to fuel switching, such as the addition of dual-fuel heat pumps.

Q: Is it appropriate for the decoupling mechanism to compensate Vectren for these trends?

A: No. In a normal rate case, the Commission would consider all the changes in the utility's costs and revenues—sales per customer, O&M expenses, taxes, costs of debt and equity, and other factors. In contrast, the proposed SRC would take into account only changes in sales per customer. Since the trend in sales per customer has consistently been a problem for Vectren, rather than ratepayers, this adjustment would only benefit Vectren.

The purpose of the SRC is, or should be, to leave Vectren as well off financially with the energy efficiency program and the SRC as it would have been with neither. The SRC should not become an all-purpose shield for Vectren against current market realities.

Q: How much would the SRC raise rates due to the decline in AUPC?

A: Vectren provided estimates of the margin it would receive and the amount of the annual SRC needed to make up for the shortfall from order-granted margin per customer. These values are before the implementation of any significant efficiency program.

Rate Increases Due to Vectren's Falling Margin per Customer

	Vectren North		Vectren South	
Rate Schedule	*Residential 210*	*General Service 220*	*Residential 110*	*General Service 120*
2006				
Actual Margin	$148,796,177	$44,342,392	$21,537,353	$6,770,547
SRC Amount	$12,104,660	$1,805,337	$1,814,269	$304,581
% increase	8.1%	4.1%	8.4%	4.5%
2007				
Actual Margin	$148,405,318	$43,855,775	$21,412,231	$6,724,757
SRC Amount	$15,040,471	$2,498,997	$2,078,959	$402,267
% increase	10.1%	5.7%	9.7%	6.0%
2008				
Actual Margin	$148,386,308	$43,531,849	$21,335,919	$6,697,420
SRC Amount	$17,644,178	$3,031,866	$2,295,673	$481,880
% increase	11.9%	7.0%	10.8%	7.2%

Source: Attachment 1.7 to Vectren response to CAC First Set of Data Requests

Q: How should the SRC be revised to avoid this problem?

A: As I mentioned in §IV.B, the order-granted margins in the SRC should be modified to reflect the existing usage trends. That adjustment might take one of the following forms:

- A fixed annual percentage or therm-per-customer reduction, based on the average weather-adjusted reduction over the past decade;

- A reduction that adjusts the historical trend for price elasticity and recent total price changes (dominated by commodity costs);
- An adjustment based on changes in sales by other Midwestern gas utilities without significant energy-efficiency programs;
- An annual percentage reduction consistent with the 15% offset in the proposal.[4]

The first approach would be the easiest to implement.

Q: Are there any differences in the incentives to Vectren for a 15% offset, compared to a fixed annual percentage reduction?

A: Yes. A 15% offset would result in Vectren losing additional margin for every Dth of gas it conserves. The most profitable strategy for Vectren would be to implement no DSM and collect the SCR for 85% of the margin reduction from continuing trends.

In contrast, a fixed annual percentage reduction in margin, combined with 100% recovery of the difference between target and actual margin, would fully protect Vectren from the margin loss of any additional gas conservation. Vectren's profitability should not vary significantly with the scale of the DSM program.

B. Duration of the Decoupling Plan

Q: Why does the duration of a decoupling plan matter?

A: Decoupling plans generally lock in margins, subject to various automatic adjustments. The utility's cost per customer may rise over time, due to inflation, or fall, due to retirement of high-priced older debt, automation of metering and billing, and other technological improvements. Leaving a decoupling plan to run for many years

[4]Vectren's filing does not demonstrate that the 15% offset approximates the "level of reduced customer usage would occur irrespective of the Efficiency Program" that Vectren claims it represents.

without regulatory scrutiny could result in much higher charges to customers than would have occurred under regular cost-of-service regulation.

Q: How often would the inputs to the SRC computation be revised?

A: It appears that the proposal contemplates that revisions to the SRC computation, including the margin per customer and the base target margin for each class, would be considered only in rate cases. As I read the proposal, the SRC and other portions of the efficiency program and the cost recovery mechanism would be reviewed in a filing in the fourth year of the program.

Q: What frequency of review would be implied by those rules?

A: For Vectren South, which will not have an SRC until the end of its forthcoming rate case, the SRC parameters would apparently be established in 2007. Assuming that the program starts in late 2006, the fourth year would start in late 2009 and end in late 2010. Hence, the review would start roughly three years after the beginning of the program.

For Vectren North, Vectren proposes that the SRC start immediately, without any updating of margin data that are significantly outdated. Paragraph 36 of the settlement proposes that "Vectren North may...file a [rate] case [no] earlier than April 1, 2007.... To facilitate the mid-term comprehensive review of its financial results, the SRC and the EEFC, Vectren North commits that it will file such a case no later than April 1, 2009." If the initial SRC parameters are set reasonably in 2006, and appropriately trended, the initial parameters cannot be in effect for much more than three years (if the rate case is filed as late as allowed in the settlement) and the revised parameters cannot be in effect for more than three years (from late 2007 to late 2010).

Q: Are the frequencies of review established in the settlement appropriate?

A: Yes. The time periods implied by the Settlement are adequate for initial reviews. If the timing of rate cases changes, the Commission should not allow the SRC to continue to operate for more than three years without review. The same is true beyond the next rate case; if the utility operates for more than three years without a rate case, the Commission should review the operation of the SRC..

VI. Alternative SRC Proposal

Q: Have you developed an alternative SRC to resolve the problems you have identified?

A: Yes. Were the Commission to adopt the SRC, I would propose amending it as follows:

- The target (or order-granted) margin for Vectren North should be updated, preferably by starting the SRC after a new rate case.[5] In the alternative, the customer number and margin can be updated to estimated 2006 values. According to Vectren's Attachment CAC 1-11 provided through discovery, these are as follows:

	Residential 210	General Service 220
Actual Customer Count	506,035	48,590
2006 Base per Customer	$294.04	$912.58

- The first SCR filing for Vectren North would occur April 1, 2008, based on actual 2007 margins. The first SCR filing for Vectren South would depend on the timing of the rate case.
- Beyond 2006, the target margin per customer should decline 1% annually. This value is less than the decline in AUPC Vectren projects for 2007 and 2008, but

[5]Since the proposed SRC would not take effect for Vectren South until after its next rate case, the SRC for Vectren South would start with updated sales and margin data.

the decline in margin is less than the decline in AUPC. If the Oversight Board can develop a method for tying the target margin directly external data (e.g., commodity prices, usage by customers of other utilities), the Commission can consider replacing the 1% decline with that method.

- Vectren should be required to report to the Commission annual data on factors —other than efficiency programs—that would affect the average use of new customers. These include floor area, the penetration of gas end uses (e.g., the portion with gas space heating, water heating, cooking, clothes drying), and the penetration of dual-fuel technologies (e.g., dual-fuel heat pumps). If these data indicate that new customers are inherently significantly smaller or larger gas users than existing customers (due to factors other than efficiency), any party should be allowed to petition the Commission for a revision to the incremental target margin per net new customer.
- Vectren should also be required to report to the Commission on conversions of master-metered buildings and single large customers to multiple small customers. If these conversions appear to be significant, any party should be allowed to petition the Commission for a revision to the incremental target margin for those new customers who are not really new loads.
- The Commission could allow any party to petition for modification of the SCR, in the event of a major economic downturn.

Q: How would the results of your proposal differ from those of Vectren's?

A: I compare the proposals in CAC Exhibit No. PLC-3, using 2006 data from Attachment 1.9 for Vectren North residential volumes and margin, and assuming that a DSM program would have reduced per-customer margin by 1%.[6] As shown in that

[6]The program defined in Exhibit DAK-S2 would save only 116 MDth, or less than 0.2% of the volumes for the eligible classes; margin losses would be even smaller. Were the program to remain that

exhibit, the settlement-proposed SRC would not fully protect Vectren from lost margins due to Company-sponsored energy-efficiency, but would give Vectren over $10 million in extra revenues, even if the efficiency program never saved a therm of gas. Even including the efficiency program that I assumed, the settlement-proposed SRC would give Vectren nearly eight times the margin it would lose due to the DSM program. Thus, the settlement proposal fails in both efficiency (since Vectren would still have incentive to defer DSM) and equity (since Vectren would get a $10-million windfall from ratepayers).

The SRC I propose, on the other hand, would give Vectren the same margin either with or without a DSM program as Vectren would have received in the base case of no DSM program and no SRC. My SRC approach would achieve the purpose of an SRC, removing the utility's disincentive for supporting DSM, without giving Vectren a $10 million windfall.

Q: If the Commission is not able to determine the form of an appropriate SRC at this time, how should it proceed?

A: The Commission should approve the rest of the proposal, with the amendments proposed by Mr. Smith, and order that the Oversight Board develop estimates of the revenues lost due to the efficiency program. Lost margins lag the development and implementation of programs, and build over time, so the Oversight Board will have ample time to estimate lost margins before they become significant. This method is used by most of the utilities that recover lost margins.

That explicit computation of lost revenues can be replaced by decoupling, if and when the Commission develops a method it deems suitable.

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small, the SRC would continue to function overwhelmingly to protect Vectren from shrinkage in customer volumes due to causes other than the effects of its efficiency programs. I hope that the program grows substantially over the next few years.

Q: What are the relative advantages and disadvantages of decoupling, as in the proposed SRC, and explicit recovery of identifiable lost margins?

A: The major advantages of decoupling, when done correctly, are that it is generally simple to administer once established (as illustrated by Exhibit No. JLU-5 and Attachments 1.8 to 1.11 to CAC First Set of Data Requests) and that decoupling can make the utility indifferent to all causes of beneficial reduced sales, whether its own programs, state codes, Federal efficiency standards, or other initiatives. The disadvantages of decoupling are as follows:

- The task of establishing the system in advance to avoid the problems discussed in §§III–V, is complex. The need to ensure that the decoupling mechanism does not provide the utility with perverse incentives for gaming, and does not systematically give the utility much higher (or lower) margins than it would have received under regulation, is especially important.
- The loss of incentives for the utility to maintain or expand beneficial sales.

The major advantage of explicit recovery of identifiable lost margins is that it is very easy to establish; the Commission simply states the policy of allowing the utility to recover margins lost due to its DSM programs and the establishes the procedures for development and review of estimated lost margins. The major disadvantage of the lost-margin recovery is the considerable complexity of reliably estimating the margins lost due to the program. Estimating lost revenues requires determination of the following values:

- The number of actions (homes visited, incentives issued).
- The savings per action (which requires information or estimates of such factors as the amount of space affected, the sizing of the equipment, hours of use, and the baseline efficiency).
- The amount of the savings that would have occurred without the utility program (so-called free ridership).

- The distribution of savings across the rate blocks, and for some programs, the distribution of savings across rate classes.

If these values are not properly estimated, the utility will over-collect or under-collect for lost margins, and it may have incentives to tamper with the mix of participants by size or measure type. The estimation of savings is often contentious among the parties (specifically between the utility and other parties), although these disputes are usually sorted out among the parties and few arguments are typically taken to the regulator for adjudication.

Q: Does this conclude your testimony?

A: Yes.

CAC Exhibit No. PLC-1

PAUL L. CHERNICK

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SUMMARY OF PROFESSIONAL EXPERIENCE

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

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

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

EDUCATION

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

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

HONORS

Chi Epsilon (Civil Engineering)

Tau Beta Pi (Engineering)

Sigma Xi (Research)

Institute Award, Institute of Public Utilities, 1981.

PUBLICATIONS

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

REPORTS

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

PRESENTATIONS

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

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

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

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

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

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

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

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

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

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"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.

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

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

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

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

115. **Michigan PSC** U-10335; Consumers Power Rate Case; Michigan United Conservation Clubs; October 1993.

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

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

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

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

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

118. **Vermont PSB** 5270-CV-1,-3, and 5686; Central Vermont Public Service Fuel-Switching and DSM Program Design, on behalf of the Vermont Department of Public Service. Direct, April 1994; rebuttal, June 1994.

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

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

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

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

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

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

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

122. **Michigan PSC** U-10554, Consumers Power Company DSM Program and Incentive; Michigan Conservation Clubs. November 1994.

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

123. **Michigan PSC** U-10702, Detroit Edison Company Cost Recovery, on behalf of the Residential Ratepayers Consortium. December 1994.

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

124. **New Jersey Board of Regulatory Commissioners** EM92030359, Environmental costs of proposed cogeneration; Freehold Cogeneration Associates. November 1994.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Allocation of costs and benefits to rate classes.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Performance incentives proposed for the Boston Edison company.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

164. **Washington UTC** UE-981627; PacifiCorp–Scottish Power Merger; Office of the Attorney General. June 1999.

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

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

Review of proposed performance standards and valuation of performance.

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

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

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

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

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

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

169. **Ontario Energy Board** RP-1999-0034; Ontario Performance-Based Rates; Green Energy Coalition. September 1999.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

180. **Connecticut DPUC** 99-09-03; Connecticut Natural Gas Corporation Merger and Rate Plan; Connecticut office of Consumer Counsel. September 2000.

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

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

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

182. **MDTE** 01-25; Purchase of Streetlights from Commonwealth Electric; Cape Light Compact. January 2001

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

194. **Vermont PSB** 6596; Citizens Utilities Rates; Vermont Department of Public Service. Direct, March 2002; Rebuttal, May 2002.

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

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

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

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

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

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

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

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

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

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

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

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

Application of rate cap. Legislative intent.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

212 **Connecticut DPUC** 03-07-01RE03 & 03-07-15RE02; Incentives for power procurement; Connecticut Office of Consumer Counsel, September 2005

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

213 **Connecticut DPUC** 05-10-03; Time-of-use, interruptible and seasonal rates; Connecticut Office of Consumer Counsel, February 2006

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

CAC Exhibit No. PLC-2:
Volumes and Average Use per Customer, 2002–2010

#NAME?

	2002	2003	2004	2005	2006	2007	2008	2009	2010
GAS NORTH									
RESIDENTIAL - 210									
AUPC (Dth)	97.5	96.1	93.6	91.2	84.0	82.3	81.0	80.2	79.7
Customers	484,742	488,419	494,816	500,934	506,035	514,039	522,168	530,427	538,816
Volumes (MDth)	47,262	46,937	46,315	45,685	42,507	42,305	42,296	42,540	42,944
Volume reduction		-0.7%	-1.3%	-1.4%	-7.0%	-0.5%	0.0%	0.6%	0.9%
AUPC reduction		-1.4%	-2.6%	-2.6%	-7.9%	-2.0%	-1.6%	-1.0%	-0.6%
GENERAL SERVICE - 220									
AUPC (Dth)	448.3	440.4	428.0	415.7	393.0	385.1	379.3	375.5	374.2
Customers	47,028	46,932	47,362	48,304	48,590	48,808	49,028	49,249	49,470
Volumes (MDth)	21,083	20,669	20,271	20,080	19,096	18,796	18,596	18,493	18,512
Volume reduction		-2.0%	-1.9%	-0.9%	-4.9%	-1.6%	-1.1%	-0.6%	0.1%
AUPC reduction		-1.8%	-2.8%	-2.9%	-5.5%	-2.0%	-1.5%	-1.0%	-0.3%
GAS SOUTH									
RESIDENTIAL - 110									
AUPC (Dth)	88.3	86.1	81.5	75.4	68.2	66.8	65.8	65.1	64.7
Customers	100,000	100,076	100,491	100,842	101,261	101,866	102,475	103,088	103,704
Volumes (MDth)	8,830	8,617	8,190	7,604	6,906	6,805	6,743	6,711	6,710
Volume reduction		-2.4%	-5.0%	-7.2%	-9.2%	-1.5%	-0.9%	-0.5%	0.0%
AUPC reduction		-2.5%	-5.3%	-7.5%	-9.5%	-2.1%	-1.5%	-1.1%	-0.6%
GENERAL SERVICE - 120									
AUPC (Dth)	441.5	438.5	427.1	405.1	374.1	366.6	361.1	357.5	356.2
Customers	10,058	10,021	10,233	10,334	10,352	10,428	10,505	10,582	10,659
Volumes (MDth)	4,441	4,394	4,371	4,186	3,873	3,823	3,793	3,783	3,797
Volume reduction		-1.1%	-0.5%	-4.2%	-7.5%	-1.3%	-0.8%	-0.3%	0.4%
AUPC reduction		-0.7%	-2.6%	-5.2%	-7.7%	-2.0%	-1.5%	-1.0%	-0.4%

Source: Attachment 1.7 to Vectren response to CAC First Set of Data Requests

CAC Exhibit No. PLC-3:
Comparison of Vectren and CAC Decoupling Approaches

Assumptions (Vectren North Residential 2006)

Rate Case Margin Per Customer (MPC)	$317.96
Trended Natural MPC	$294.04
MPC with 1% DSM reduction	$291.10
Rate Case Number of Customers	496,013
Actual Number of Customers	506,035

	Formula	Without DSM Program	With DSM Program	Vectren Gain Compared to: Without DSM	Vectren Gain Compared to: With DSM	Vectren Loss from DSM	Notes
Without SRC	Actual MPC	$294	$291				
	× Actual Number of Customers	506,035	506,035				
	Margin	$148,796,177	$147,308,215	Base	$147,307,924	$1,487,962	DSM reduces margin
Settlement Proposed SRC	Rate Case MPC	$0	$0				
	– Actual MPC	$0	-$291				
	MPC Differential	0	-291				
	× Actual Number of Customers	506,035	506,035				
	Margin Differential	$0	($147,308,215)				
	× 85%	85%	85%				Margin greater than Base, with or without DSM
	SRC	$0	($125,211,983)				
	+ Actual Margin	$148,796,177	$147,308,215				
	Total Margin	$148,796,177	$22,096,232	$148,795,886	$22,095,941	$126,699,945	DSM reduces margin
With 100% SRC and Trended Margin	Trended Natural MPC	$294	$294				
	– Actual MPC	$0	-$291				
	MPC Differential	294	3				
	× Actual Number of Customers	0	0				Margin same as Base, with or without DSM
	SRC	$0	$0				
	+ Actual Margin	$148,796,177	$0				
	Total Margin	$148,796,177	$0	$148,795,886	-$291	$148,796,177	DSM does not reduce margin

CERTIFICATE OF SERVICE

The undersigned hereby certifies that the foregoing document has been served upon the following by first class, United States mail, postage prepaid on June 26, 2006:

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