COMMONWEALTH OF MASSACHUSETTS

DEPARTMENT OF PUBLIC UTILITIES

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INVESTIGATION INTO THE PRICING AND RATEMAKING TREATMENT TO BE AFFORDED NEW ELECTRIC GENERATING FACILITIES WHICH ARE NOT QUALIFYING FACILITIES

TESTIMONY OF PAUL L. CHERNICK ON BEHALF OF

THE CONSERVATION LAW FOUNDATION

AND

ACTION, INC.
CENTER FOR ECOLOGICAL TECHNOLOGY
ENERGY CONSERVATION COALITION
ENERGY FEDERATION, INC.
FUNDAMENTAL ACTION TO CONSERVE ENERGY
MASSACHUSETTS AUDUBON SOCIETY
MASSACHUSETTS CITIZEN ACTION
MASSACHUSETTS PUBLIC INTEREST RESEARCH GROUP
NATURAL RESOURCES DEFENSE COUNCIL

May 2, 1988

TESTIMONY OF PAUL CHERNICK

on behalf of the

Conservation Law Foundation

1. INTRODUCTION AND QUALIFICATIONS

Q: Would you state your name, occupation and business address?

A: My name is Paul L. Chernick. I am President of PLC, Inc., 18 Tremont Street, Suite 703, Boston, Massachusetts.

1.1. Qualifications

Q: Mr. Chernick, would you please briefly summarize your professional education and experience?

A: I received a S.B. degree from the Massachusetts Institute of Technology in June, 1974 from the Civil Engineering Department, and a S.M. 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 over three years, and was involved in numerous aspects of utility rate design, costing, load forecasting, and the evaluation of power supply options.

As a Research Associate at Analysis and Inference, and in my current position, I have advised a variety of clients on utility matters. My work has considered, among other things, the need for, cost of, and cost-effectiveness of prospective new generation plants and transmission lines; retrospective review of generation planning decisions; ratemaking for plant under construction; and ratemaking for excess and/or uneconomical plant entering service. My resume is attached to this testimony as Appendix A.

Q: Mr. Chernick, have you testified previously in utility proceedings?

A: Yes. I have testified approximately sixty times on utility issues before various agencies including this Commission, the Massachusetts Energy Facilities Siting Council, the Illinois Commerce Commission, the Texas Public Utilities Commission, the New Mexico Public Service Commission, the District of Columbia Public Service Commission, the New Hampshire Public Utilities Commission, the Connecticut Department of Public Utility Control, the Michigan Public Service Commission, the Maine Public Utilities Commission, the Vermont Public Service Board, the Minnesota Public Utilities Commission, the Federal Energy Regulatory

Commission, and the Atomic Safety and Licensing Board of the U.S. Nuclear Regulatory Commission. A detailed list of my previous testimony is contained in my resume. Subjects I have testified on include cost allocation, rate design, long range energy and demand forecasts, utility supply planning decisions, conservation costs and potential effectiveness, generation system reliability, fuel efficiency standards, and ratemaking for utility production investments and conservation programs.

Q: Have you previously testified before this Commission?

A: Yes. I have testified in about two dozen proceedings before the Commission, on rate design, power plant performance standards, conservation potential and cost, QF rates, nuclear power plant costs, and other topics.

Q: Have you authored any publications on utility ratemaking issues?

A: Yes. I have authored a number of publications on rate design, cost allocations, power plant cost recovery, and other ratemaking issues. These publications are listed in my resume.

Q: Have you advised any regulatory agencies on least-cost planning issues?

A: Yes. I am the senior economic advisor to the District of Columbia Public Service Commission in Formal Case 834, Phase II, a comprehensive review of the potential benefits of least-cost planning for both electric and gas utilities in DC. Order No. 8974 in that case, issued March 16, 1988, has been viewed as placing DC in the front rank of jurisdictions requiring their utilities to engage in least-cost planning.

I am currently the project manager and senior investigator for a least-cost planning project for the Minnesota Department of Public Service, which has a distinct set of energy-regulatory responsibilities, and also serves an intervention function similar to that often performed by PUC staff. In that project, we are estimating the potential for cost-effective conservation and load management in Minnesota.

1.2. Purpose of This Testimony

Q: What is the purpose of your testimony?

A: I will discuss various financial and ratemaking issues which arise in structuring and evaluating utility-sponsored energy efficiency programs. The areas I will cover include the timing and form of the utility's recovery of its costs associated with the efficiency program, the effects on participants and non-participants, and the structure of ratemaking incentives for utility implementation of cost-effective energy-efficiency programs.

Rather than discussing these issues in the abstract, I will cover them as I describe the generalized financial model that the Conservation Law Foundation (CLF) has developed to represent the effects of efficiency programs. This model is primarily my work product, although some of the initial directions were defined by CLF staff. The model permits the Department to determine the effect of efficiency programs on the utility/ratepayer system as a whole, and also the separate effects on the utility, on the program participants and on non-participants, including the effects of recovering the revenues lost due to the sales reductions caused by the program. The model also allows the Department to study the effect of explicit performance-based incentives on the utility and on the ratepayers.[1]

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1. In demonstrating the possible structure of such an incentive, neither I nor CLF is endorsing any particular level of incentive for any particular utility. I discuss how the incentive should be structured, if it is needed and appropriate; whether any incentive is justified, and if so at what level, depends on a number of utility-specific factors.

2. THE CLF FINANCIAL MODEL

Q: Have you included an example of that model with this testimony?

A: Yes. Appendix B is a run of the model, assuming no costs of the conservation program are recovered specifically from participants. Appendix C is a similar run, but with 20% of program costs charged back to the customers participating in the program.

Q: Do these runs represent specific utilities and conservation program proposals?

A: No, they are primarily illustrative in nature. I am not sponsoring testimony on the validity of the inputs to the examples. However, they are representative of situations the Commission might well see in the future. Current sales, avoided costs, sales forecasts, and average rates were selected to approximate those of Boston Edison (BECO), as the largest electric utility in the Commonwealth and the most familiar point of reference for people familiar with Massachusetts electric utility regulation. The magnitude of the conservation program, and its anticipated savings and cost, are scaled up from CLF's proposal for Central Maine Power (CMP). Since BECO is about twice the size of CMP, I have doubled the scope of the proposed program. Some of the data I have used for BECO are slightly out of date, but they are sufficient for our illustrative purposes.

Q: Please explain the organization of the financial model runs.

A: The organization of each example is the same. Table 1 provides capital structure inputs and computes levelized carrying charges. Table 2 summarizes the major inputs: the avoided cost projection; the scale of the conservation program, in dollars of investment and in annual GWH saved; the share of the program cost paid by the utility, rather than by the participants; and total GWH sales projected in the absence of the program. The inputs are defined for program measures of differing lives: in this example, measures with 15-year and 20-year lives are modeled. Table 2 also provides a test of annual program cost-effectiveness, by computing the levelized cost of each year's investment in the conservation program in cents/kWh, and comparing that cost to the utility's levelized avoided cost over the period affected by measures installed in that year. Table 2 contains too many lines to fit on a single page, so it has been split into Table 2(A) and Table 2(B).

Table 3 calculates the annual capital recovery of the investments from Table 2. The cost recovery includes depreciation, and returns and taxes on the undepreciated investment, both calculated from the total investment to date.

Table 4 compiles the current ratemaking benefits and costs of the conservation program, as well as restating the levelized values from Table 2, as total costs and benefits from all of the measures in service in the particular year. Table 4 also computes that effect of the program on load growth. Finally, Table 4 computes the lost utility revenues, an incentive payment to the utility, and the net annual cost (or savings) to ratepayers from the program. Table 4 is also split in two parts, as is Table 2.

Table 5 separates the effects of the conservation program between participants and non-participants.

Table 2 through 5 present projections for the period 1988-2008. The last five years are presented on a second page of output, in each case.

2.1. Financial Inputs and Assumptions

Q: Returning to Table 1, please summarize the calculations presented at the top of that table.

A: The top section of Table 1 includes the capital structure inputs: the percentage of capital contributed by each source (debt, preferred stock, and equity), and the cost of each capital source. The income tax rate is also entered in this section. The table then computes the weighted cost of capital (labeled "CC") or return, and the weighted sum of return and taxes (labeled "RT"), as a percentage of net plant.

Q: How have you treated deferred taxes and property taxes in this example?

A: I have assumed that neither will affect the cost of the program. Specifically, I do not know how the Federal IRS and the Massachusetts Department of Revenue would determine the tax life of the conservation investments, and have assumed that the tax life would be the same as the tax life used in ratemaking. It is possible that the treatment would be much more favorable to the utility. At the extreme, the entire conservation expenditure might be expensed for tax purposes, since investment would not produce any utility-owned property. In that case, the levelized carrying charges would be significantly lower, especially for the longer-lived measures.

Since the utility will generally not own the property installed as a result of conservation programs, it seems unlikely that any significant property taxes would result.

Q: What is the meaning of the lower part of Table 1?

A: This section computes the levelized capital recovery factors (LVCs) for conservation measures, or any other similar investment for that matter. The LVC is the constant percentage charge that has the same present value as the sum of depreciation plus return and taxes on undepreciated plant, over the life of the conservation measure. The levelization is performed by discounting at the cost of capital. I have presented LVCs for conservation measures with lives of 5, 10, 15, and 20 years.

2.2. Efficiency Program Inputs and Assumptions

Q: What does Table 2 show?

A: This table starts (line 2) by presenting projected avoided costs, in cents/kWh. In our example, these are taken from BECO's 11/86 avoided cost estimates, for sales at secondary voltage. These avoided costs do not include avoided transmission and distribution investments, which would add a significant increment to the benefits of conservation.

Table 2 continues with summaries of the conservation program, disaggregated by the lifetime of the measures installed. Since the levelized costs and benefits depend on the life of the measures, the conservation program investment must by disaggregated by the lifetime of the investments. In the example, I have illustrated 15-year and 20-year measures. For clarity, I will refer to the line numbers for the 15-year measures.

For each measure life, I have specified an annual level of investments (line 3, for the 15-year measures) and annual energy savings (line 4). Line 5 calculates the levelized cost of energy for that year's investments, using the LVC calculated on Table 1. Line 6 allows the user to specify the percentage of the program cost in each year borne by the utility, as opposed to the participating customers. Line 7 calculates the levelized cost of that year's investment in cents/kWh, from the avoided costs on line 3. The savings are assumed to start in the year following the investment: in general, I have assumed that all investments are made at year-end. Line 8 calculates the dollar avoided cost savings due to each year's investment in 15-year measures, since this value will be useful in construction Table 4.

Lines 9-14 repeat the same inputs and calculations for the measures with lives of 20 years.

Lines 15, 16, and 20 (which are on part B of Table 2) compute the total investment costs, GWH savings, and dollar savings from the investments in each year. Lines 17 and 19 present the average savings and costs in cents/kWh from investments in the year, and line 18 summarizes the average utility share of program cost.

Line 21 is an input line, for total energy sales expected in the absence of the conservation program. Line 22 computes the average annual growth rate without the conservation program, from 1988 to each later year.

Line 23 presents an estimate of the cumulative percentage of sales-weighted customers participating in the program. I have assumed for this purpose that the average participant achieves a 50% reduction in sales. The sales-weighted customer percentage may be thought of as the percentage of sales (without the program) which would have been to the customers who participated. We must make some assumption about the share of pre-program sales to participants in the program, in order to sort out the effects of the program on participants and on non-participants.

2.3. Conservation Program Cost Recovery

Q: Are the inputs from Table 2 carried over onto Table 3?

A: Yes, some of them are. Specifically, Table 3 computes the current cost recovery (depreciation, return, and taxes) from the utility's previous investment in the conservation program.

Q: How is current cost recovery different than the levelized costs your presented in Table 2?

A: The levelized costs in Table 2 refer only to the measure installed in that year. In reality, ratepayers would pay in each year for measures installed and capitalized in many prior years. Also, the Table 2 costs were levelized, so that the same amount was charged in each year. Normal ratemaking practice charges ratepayers more for an investment in the first year of its life, with the charge gradually decreasing as the original investment is depreciated.

Levelized costs are appropriate for judging the cost-effectiveness of each program in each year, while the current costs and benefits determine the effect on rates and bills in each year.

Q: Do you assume that all the costs associated with the conservation program will be capitalized?

A: Yes.

Q: Why do you make that assumption?

A: Capitalizing all of these conservation program costs is logically appropriate, equitable, and consistent with standard utility practice in supply planning. This conclusion follows from the fact that none of the conservation programs CLF proposed in the CMP package (which was used as the model for my example) had any significant on-going costs, once the measures were in place. In other words, there would be no operating costs. For a program with significant continuing costs an operating cost component should be added.

All of the pre-operation costs of a conservation measure should be capitalized. Utilities generally capitalize the costs of planning, designing, supervising, and managing power plant construction, and the same treatment appears to be appropriate for the start-up and overhead costs of conservation programs. It would be inequitable to charge current ratepayers, who can not yet use a future power plant, to pay for its design and supervision. Charging current ratepayers for conservation which is not yet in service would be similarly inequitable.

Q: How is Table 3 organized?

A: Table 3 is split into three sections, covering 15-year measures, 20-year measures, and the total program. For the 15-year measures, line 2 carries over the utility's share of the additions to conservation investment from line 3 of Table 2. If the participants are charged directly for a portion of the program, those costs are excluded from this calculation. Line 3 calculates straight-line depreciation on the gross plant, which is equal to the additions in the previous 15 years. Throughout the example, I assume that all additions occur at the end of the year. Line 4 computes the year-end rate base, which is equal to the previous year's rate base, plus additions in the current year, minus depreciation in the current year. Line 5 computes return and taxes, as the previous year's rate base multiplied by the RT factor from Table 1. Line 6 presents the total cost recovery, which is the sum of depreciation, return, and taxes.

Lines 7-11 present the same calculations for the 20-year measures, and lines 12-16 add up the corresponding lines from the two previous sections, to compute total values for the program.

Q: What are the figures to the right of the entries for 2008?

A: Those are present values of the revenues from the cost recovery lines. Following general utility and DPU practice, I have discounted the costs at the utility's cost of capital.

2.4. Annual Cost and Benefit Comparisons

Q: Table 4 starts with annual energy savings. Are these the same figures presented as inputs in Table 2?

A: No. Table 2 showed the annual savings from investments made in each year, while lines 2-4 of Table 4 shows the cumulative energy saved by all measures in effect in the year. Consistent with my other assumptions, I treat each investment as saving energy in the year after the investment is made, and for a total of 15 (or 20) years thereafter. Thus, line 2 for 2003 is the sum of the energy savings from 15-year investments in 1988-2002, while the same line for 2004 is the sum of savings from installations in 1989-2003, since the 1988 installations would be retired in 2003.

Q: What else does Table 4 show?

A: Line 5 shows the sales with the program, calculated by subtracting line 4 of Table 4 from line 21 of Table 2, and the after-program growth rate. Line 7 performs the same calculation for sales to participants. The other lines in that section present summaries of the program's effects on sales and sales growth. Line 9 converts the reduction in sales into a reduction in peak load, assuming that the sales avoided through the conservation program have an average load factor of 60%, typical of BECO's system as a whole. Since the early parts of the conservation program would probably concentrate on commercial lighting and on air conditioning, the effect on BECO's summer peak would be higher than is indicated on line 9.

Lines 10-12 perform the same calculation for levelized program costs that lines 2-4 did for GWH savings. Each year's value is that year's levelized share of the costs of all the measures which are in effect in that year, e.g., those installed in the previous 15 or 20 years. This is the sum of the investments in that period, multiplied by the LVC value for the measure's life. Similarly, lines 13-15 present the total levelized avoided cost in each year, which is simply the summation of line 8 of Table 2.

Lines 16-18 present current, rather than levelized values. Line 16 computes the current avoided costs from all measures in effect in a particular year, as the product of the avoided cost per kWh (line 2 of Table 2) times the total energy savings in line 4 of Table 4. This is the benefit line which is comparable to the current costs computed in Table 3. Line 17 is an input line, for the average revenue reduction due to each kWh of sales avoided savings by the number of kWh prior to the program, to derive the average savings per pre-program kWh.

2.4.1. Incentive Payments to Utilities

Q: Are you endorsing any particular level of incentive to utilities?

A: No. I have included this feature in the model to illustrate one simple way of incorporating an incentive. The important feature of the incentive is that it treats all savings equally, and is based on net benefits to ratepayers, rather than on just the amount of money spent (as would a rate-of-return bonus on conservation investment) or the number of kWh saved.

Compared to some other incentive mechanisms proposed in New England, the incentive used in the examples is quite simple and straightforward. For example, Commissioner David Moskovitz of the Maine PUC has proposed that utility rate of return be tied to the movement of average customer bills, compared to a regional index.[2] Commissioner Moskovitz's approach is appealing in principle, but has a number of practical problems, such as the need to adjust for changes in customer mix, for the efficiency levels of existing customers of differing utilities, for the effects

2. Moskovitz, David, Will Least Cost Planning Work Without Significant Regulatory Reform?, NARUC Least Cost Planning Seminar, Aspen CO, April 12, 1988.

of weather and the economy, and for the differences in the base costs and cost structures of different utilities. If the Commission finds that an incentive is appropriate, especially in the transition period in which conservation programs may expose utilities to new risks, the form of incentive I have outlined would be appropriate.

I have not reached a judgment as to whether any special incentives are appropriate. Utilities have historically been reluctant to invest in conservation, for a variety of reasons. While I believe that utilities have an obligation to make socially cost-effective investments in energy efficiency, without any special compensation, such compensation may be useful in overcoming institutional resistance. Ultimately, the Commission must decide how to balance the application of carrots and of sticks. I would expect that the carrots would be easier to implement and more effective, since the utilities would be more cooperative. However, there are always equity concerns in giving utilities special treatment for taking actions they should take as a part of normal business practice.

Q: What is the practical effect on the utility of the incentive you have used in your example?

A: The effect varies from year to year, so it is difficult to generalize. In 1996, when the program is in full bloom, the utility incentive would be $24.5 million, or about $15.1 million after tax. Boston Edison, to which our example is scaled, has roughly $800,000,000 in common equity.[3] The $15.1 million in after-tax incentive would add 190 basis points (1.9 percentage points) to the allowed return on equity. This is a very large incentive, equivalent to almost a sixth of Boston Edison's last allowed equity return, and almost twice the size of the apparent rate-of-return penalty for past inactivity on conservation.

2.5. Effects on Participants and Non-participants

Q: Please describe Table 5.

A: Table 5 computes the costs and benefits of the program from the perspective of participants, and then from the perspective of non-participants. Lines 2-4 total the costs of the conservation program which are recovered directly from participants in each year. I have assumed that the cost recovery is levelized over the life of the measures, for simplicity in the analysis. Actual cost recovery is apt to be either levelized over the life of the measure,

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3. This is the year-end 1986 value. The equity invested in utility operations is not likely to increase very rapidly, unless the utility undertakes a major construction program. Otherwise, additional retained earnings would generally be used in non-utility investments. Pilgrim retrofit investments may raise the equity investment in electric operations, or Pilgrim-related write-offs may decrease the company's equity. Hence, the direction of change from 1986 to 1996 is not clear.

levelized over a shorter period, or phased in on a shared-savings basis.

Line 5 shows the reduction in the participants' pre-program electric bills, which is the same as the lost revenues (line 18 in Table 4). In addition, the participants' bills will rise, along with all other customers' bills, to reflect the recovery of the lost revenues, and fall due to the utility costs avoided. Lines 6 and 7 show the participants' share of these two costs. Line 8 computes the net benefit to participants, which is line 5 plus line 7, minus lines 4 and 6. Line 9 computes the reduction in participant costs, in cents per pre-program kWh.

Line 10 is the net benefit to non-participants, which is just the total ratepayer benefits (line 22 of table 5) minus the benefits to participants (line 8). This benefit starts out negative, and remains negative for many years, but eventually becomes positive. It is less negative in Appendix C, with 20% of costs charged directly to participants, than in Appendix B, with all costs flowed through rates. Line 11 restates the net benefit in cents/kWh.

2.6. Discussion of Example Results

Q: Please discuss the results of your examples.

A: On a levelized basis, the program is beneficial right from the start, and for every year. On a current basis, the program increases total costs slightly for the first four years, but then delivers much larger savings. The current-cost burden in the first few years never rises above a mill/kWh, and is somewhat lower if participants pick up some of the costs directly. The charges to the participants are levelized, reducing the net cost in the early years of the program. Alternatively, the utility could make current benefits in all years positive by deferring some costs from years 1-4, and recovering them in year 7.

By the end of our analysis in 2008, the net benefits would be $2.3 billion on a levelized basis and $1.7 billion on a current basis, without any direct charges to participants. Even if investments were halted in 2008, benefits and costs would continue to accrue for additional decades: the net benefits would continue to grow, especially on a current basis. Thus, the net benefit figures in Appendices B and C understate the true benefits of the program.

Participants benefit significantly from the program, regardless of whether they are charged directly for some of the program costs. Non-participants, on the other hand, are worse off into the next century, by up to about 1.5 cents/kWh in various years. After the turn of the century, the rising avoided costs and the amortization of the original conservation make the conservation economical for the non-participants. Over the life of the conservation investments, the non-participants may well be better off with the conservation program than without it. However, the significant (though not overwhelming) short-term increases will be burdensome for some non-participants. This illustrates the importance of offering a wide variety of conservation programs, to allow as widespread participation as possible. Also, increasing the share of costs recovered from participants and their rate classes reduces the burden on non-participants. For example, recovering 20% of the costs from participants reduces the net present value of the non-participant cost by almost 40% through 2008, and recovering 50% of the costs from participants would essentially eliminate the net cost to non-participants through 2008. After 2008, non-participants continue to receive increasing net benefits through the end of the measures' lives, the last of which occurs in 2028.

3. OTHER ISSUES

Q: What other issues did you wish to address, beyond the financial model of utility cost recovery?

A: I have already discussed the issue of financial incentives to the utilities. I am also available to respond to questions from the Commission regarding cost-effectiveness tests for conservation programs. I understand that this topic will be addressed by Mr. Plunkett, on behalf of the Energy Foundation, Inc., I will not file any direct testimony on the subject. The only additional topic I would like to raise at this point is the ratemaking treatment of timing problems, including the utility's recovery of increased efficiency expenditures between rate cases, and recovery of revenues lost due to conservation.

I consider two timing problems to be the primary rational obstacles to whole-hearted utility participation in conservation. First, utilities are understandably reluctant to spend millions of dollars on efficiency programs, without some assurance that the expenditures will be recoverable. I do not refer here to any guarantee that the expenditures will be found prudent, but only to the promise that the utility will have an opportunity to recovery the costs if it can demonstrate that they were prudently and efficiently incurred. Thus, whether through capitalization, through a balancing account, through deferral of some expenses, or through a fuel-clause-like automatic recovery with subsequent review, the utility must have some mechanism for recovery of direct expenditures on conservation.

Second, utilities must have some mechanism for recovering the revenues lost through an effective conservation program. Conventional ratemaking allows the utilities fixed rates per kWh sold (and for each other billing determinant, such as kW and customer-month). Once those rates have been set, the more kWh a utility can sell, the higher its revenues. Except in the now-rare circumstances in which the short-run marginal cost is higher than rates,[4] utilities have higher earnings this year if they sell more kWh this year. Obviously, utilities will be reluctant to implement effective conservation programs (although they may be willing to spend money on conservation), if those programs reduce their profitability.

The revenue erosion problem can be approached in a number of ways. One alternative is to reduce forecasted kWh sales for the proof-of-revenue calculations. This would increase the rates charged per kWh. Unfortunately, once the higher rates are set, the utility will still be better off selling as many kWh as possible this year, even while spending money on conservation and creating a record

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4. The existence of a fuel adjustment clause largely shelters utilities from short-run marginal costs, in any case.

for an even large adjustment to sales in the next rate case. In addition, the DPU's historical test year is not easily compatible with conservation sales adjustments.

There are several viable alternatives for eliminating the utility's bias towards increased sales. Some approaches use a balancing account or a mechanism similar to the fuel clause, to true-up sales to an allowed level. The costs can be recovered automatically, with later review; through regular special-purpose proceedings to set the size of a lost-revenue rider; or as a part of a full rate case. So long as demonstrably lost revenues are recoverable at some point in the future, the utility should not feel penalized by its own conservation measure.

Another approach, discussed in an article I published in Public Utilities Fortnightly, is to allow the utility to collect a buffer fund in advance, which can then be allocated to offsetting lost sales or to funding additional conservation. My article, "Revenue Stability Target Ratemaking," is attached as Appendix D.

Again, the DPU's use of an historical test year may complicate the true-up process for lost revenues. Rather than correcting for the difference between actual sales and target sales, the adjustment mechanism can be applied to the sales which the utility can demonstrate it has avoided by its actions.

Q: Some analysts have focussed on ratebasing of conservation as an incentive to utility for participation in conservation programs. Do you believe that the opportunity to earn a return on conservation investment, in itself, would make utilities enthusiastic about participation in significant programs?

A: I doubt that ratebasing, per se, would be sufficient to ensure utility acceptance or support of conservation programs. Capitalizing program costs is one way to allow utilities to avoid timing problems, and as discussed above it is essential for equitable treatment of ratepayers over time. However, from the utility's perspective, the timing problems can be solved with any of the variety of deferred or adjusted expensing mechanisms discussed above. Given the choice between faster depreciation and higher rate base, utilities generally choose faster depreciation, indicating that they tend to prefer expensing to capitalizing expenditures when they have a choice.

Q: Does this conclude your testimony?

A: Yes.

BECO Scenario 1 -- No Charges to Participants

Table 2(B):

Investment Year

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		1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	20
	Total																
15	$M invested	$4.8	$50.8	$78.3	$129.3	$148.1	$147.2	$134.6	$141.3	$142.1	$151.0	$159.7	$167.6	$176.0	$184.9	$197.2	$210.
16	MWh saved/yr	10.9	158.5	234.1	374.0	405.8	385.0	349.0	349.0	349.0	342.0	345.6	345.6	345.6	345.6	359.8	368.3
17	Cents/kWh saved	6.19	4.65	4.79	4.92	5.18	5.43	5.49	5.76	5.78	6.29	6.58	6.91	7.25	7.62	7.80	8.13
18	Utility share of program cost	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0
19	Levelized A. C., /kWh	10.56	10.96	12.51	14.14	15.50	16.95	18.45	20.11	21.85	23.67	25.57	27.52	29.52	31.58	33.65	35.74
20	Levelized A. C., $Mill	$1.2	$17.4	$29.3	$52.9	$62.9	$65.3	$64.4	$70.2	$76.3	$81.0	$88.4	$95.1	$102.0	$109.1	$121.1	$131.6
	Participation																
21	Total GWh sales w/o program	12,400	12,710	13,028	13,353	13,687	14,029	14,380	14,740	15,108	15,486	15,873	16,270	16,677	17,094	17,521	17,959
22	Percent growth since 1988		2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
23	% of Customers Participating	0%	3%	6%	11%	17%	22%	26%	30%	34%	37%	41%	44%	47%	50%	52%	55%
24	Participating Customer Sales	21	331	787	1,517	2,309	3,060	3,741	4,422	5,103	5,770	6,444	7,119	7,793	8,467	9,169	9,888

BECO Scenario 1 -- No Charges to Participants

Table 2(B):

		2004	2005	2006	2007	2008
	Investment Year					
	Total					
15	$M invested	$119.3	$120.6	$126.6	$127.4	$134.4
16	MWh saved/yr	292.1	275.8	227.1	203.8	137.9
17	Cents/kWh saved	5.77	6.18	7.87	8.83	13.77
18	Utility share of program cost	100.0%	100.0%	100.0%	100.0%	100.0%
19	Levelized A. C., /kWh	38.08	40.07	41.97	43.87	45.62
20	Levelized A. C., $Mill	$111.2	$110.5	$95.3	$89.4	$62.9
	Participation					
21	Total GWh sales w/o program	18,408	18,868	19,340	19,823	20,319
22	Percent growth since 1988	2.5%	2.5%	2.5%	2.5%	2.5%
23	% of Customers Participating	56%	57%	57%	57%	57%
24	Participating Customer Sales	10,332	10,744	11,061	11,333	11,582

Table 3: Annual Costs to Ratepayers

BECO Scenario 1 -- No Charges to Participants

This table presents a simple model of utility cost recovery. Investments enter service at the end of the year, depreciation is based on gross plant at the start of the year, and return and taxes are computed on net plant at the start of the year.

Yr Cost Recovered	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
15 year measures																
Additions	$0.2	$18.1	$18.5	$19.4	$20.4	$20.2	$21.1	$22.2	$17.1	$24.4	$26.4	$27.6	$29.0	$30.5	$32.0	$35.5
Depreciation		$0.0	$1.2	$2.5	$3.7	$5.1	$6.5	$7.9	$9.3	$10.5	$12.1	$13.9	$15.7	$17.6	$19.7	$21.8
Ratebase	$0.2	$18.3	$35.6	$52.5	$69.2	$84.3	$98.9	$113.3	$121.0	$135.0	$149.2	$163.0	$176.3	$189.2	$201.5	$215.2
Return & taxes		$0.0	$2.5	$4.8	$7.1	$9.3	$11.3	$13.3	$15.2	$16.3	$18.1	$20.1	$21.9	$23.7	$25.4	$27.1
Cost recovery		$0.0	$3.7	$7.2	$10.8	$14.4	$17.8	$21.2	$24.6	$26.8	$30.3	$33.9	$37.6	$41.3	$45.1	$48.9
20 year measures																
Additions	$4.6	$32.7	$59.8	$109.9	$127.7	$127.1	$113.4	$119.1	$125.0	$126.6	$133.3	$140.0	$147.0	$154.4	$165.1	$174.7
Depreciation		$0.2	$1.9	$4.9	$10.3	$16.7	$23.1	$28.8	$34.7	$41.0	$47.3	$54.0	$61.0	$68.3	$76.0	$84.3
Ratebase	$4.6	$37.1	$95.0	$200.0	$317.3	$427.6	$518.0	$608.3	$698.7	$784.3	$870.3	$956.4	$1,042.4	$1,128.5	$1,217.6	$1,308.0
Return & taxes		$0.6	$5.0	$12.8	$26.9	$42.7	$57.5	$69.6	$81.8	$93.9	$105.4	$117.0	$128.6	$140.1	$151.7	$163.7
Cost recovery		$0.8	$6.8	$17.6	$37.2	$59.4	$80.6	$98.4	$116.5	$134.9	$152.7	$170.9	$189.5	$208.4	$227.7	$248.0
Totals																
Additions	$4.8	$50.8	$78.3	$129.3	$148.1	$147.2	$134.6	$141.3	$142.1	$151.0	$159.7	$167.6	$176.0	$184.9	$197.2	$210.2
Depreciation		$0.2	$3.1	$7.3	$14.1	$21.8	$29.5	$36.6	$44.1	$51.4	$59.4	$67.8	$76.7	$86.0	$95.7	$106.1
Ratebase	$4.8	$55.4	$130.5	$252.5	$386.5	$511.9	$616.9	$721.6	$819.7	$919.3	$1,019.6	$1,119.4	$1,218.7	$1,317.7	$1,419.1	$1,523.3
Return & taxes		$0.6	$7.4	$17.5	$33.9	$52.0	$68.8	$82.9	$97.0	$110.2	$123.6	$137.0	$150.5	$163.8	$177.1	$190.8
Cost recovery		$0.9	$10.5	$24.9	$48.0	$73.8	$98.3	$119.5	$141.1	$161.6	$183.0	$204.9	$227.1	$249.8	$272.8	$296.9

Table 3: Annual Costs to Ratepayers

BECO Scenario 1 -- No Charges to Participants

Yr Cost Recovered	2004	2005	2006	2007	2008	Present Value @ Cost of Capital
15 year measures						
Additions	$8.4	$8.8	$9.2	$9.8	$10.6	
Depreciation	$24.2	$23.5	$22.9	$22.2	$21.5	
Ratebase	$199.5	$184.8	$171.1	$158.7	$147.8	
Return & taxes	$28.9	$26.8	$24.8	$23.0	$21.3	
Cost recovery	$53.1	$50.3	$47.7	$45.2	$42.8	$171.6
20 year measures						
Additions	$110.9	$111.8	$117.4	$117.7	$123.8	
Depreciation	$93.0	$98.6	$104.2	$110.0	$115.9	
Ratebase	$1,325.9	$1,339.2	$1,352.4	$1,360.0	$1,367.9	
Return & taxes	$175.8	$178.2	$180.0	$181.8	$182.8	
Cost recovery	$268.8	$276.8	$284.2	$291.8	$298.7	$847.6
Totals						
Additions	$119.3	$120.6	$126.6	$127.4	$134.4	
Depreciation	$117.2	$122.1	$127.0	$132.2	$137.4	
Ratebase	$1,525.4	$1,523.9	$1,523.5	$1,518.7	$1,515.8	
Return & taxes	$204.8	$205.0	$204.8	$204.8	$204.1	
Cost recovery	$321.9	$327.1	$331.9	$337.0	$341.5	$1,019.2

Table 4(A): Annual Levelized Costs, Benefits, and Incentives

Energy savings from Table 2 are repeated on lines 2-4. Lines 5 & 7 calculate sales with the program, both for the entire utility and for the participants, and lines 6 & 8 compute the % reduction in sales due to the program. Line 9 converts the energy savings to MW savings. Levelized program costs are computed (lines 10-12), as are levelized and current benefits (lines 13-15). A ¢/kWh value for lost revenues is input to line line 17, and total lost revenues calculated. Net social benefits are calculated as the difference between previously calculated benefits and costs, on both levelized (line 10 - line 12 and current (line 12 - line 26, Table 3). The utility incentive payment is calculated as a % of line 19, and the remaining ratepayer savings are computed. The ratepayer savings are converted to ¢/kWh, based on the sales prior to the conservation program.

		1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
1	Year:	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
	Energy Savings (GWH)																
2	15-yr measures		0	65	129	194	258	318	377	437	496	555	617	678	740	801	863
3	20-yr measures		11	105	274	584	925	1,250	1,540	1,830	2,119	2,402	2,686	2,970	3,254	3,538	3,837
4	Total		11	169	404	777	1,183	1,568	1,917	2,266	2,615	2,957	3,303	3,648	3,994	4,339	4,699
	Sales w/ program																
5	Total	12,400	12,699	12,858	12,950	12,910	12,846	12,812	12,823	12,842	12,871	12,916	12,967	13,028	13,100	13,181	13,260
6	% reduction		0%	1%	3%	6%	8%	11%	13%	15%	17%	19%	20%	22%	23%	25%	26%
	% growth from 1988		2.4%	1.8%	1.5%	1.0%	0.7%	0.5%	0.5%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%
7	Sales to Participants	43	650	1405	2631	3840	4937	5913	6926	7939	8925	9931	10935	11938	12941	13999	15077
8	% reduction		2%	11%	13%	17%	19%	21%	22%	22%	23%	23%	23%	23%	24%	24%	24%
9	MW Load Reduction @ load factor =	60%	2	32	77	148	225	298	365	431	498	563	628	694	760	826	894
	Levelized Program Costs ($ million)																
10	15-yr measures		$0.0	$2.8	$5.6	$8.6	$11.8	$14.9	$18.1	$21.5	$24.1	$27.9	$31.9	$36.2	$40.6	$45.3	$50.2
11	20-yr measures		$0.6	$5.2	$13.6	$29.0	$46.9	$64.7	$80.7	$97.4	$114.9	$132.6	$151.3	$171.0	$191.6	$213.3	$236.4
12	Total		$0.7	$8.0	$19.3	$37.7	$58.7	$79.6	$98.8	$118.9	$139.0	$160.5	$183.3	$207.1	$232.2	$258.5	$286.6

APPENDIX A

DIRECT TESTIMONY OF

PAUL L. CHERNICK

on behalf of the

CONSERVATION LAW FOUNDATION

* * *

Resume of Paul L. Chernick

PAUL L. CHERNICK

PLC, Inc.
18 Tremont Street
Boston, Massachusetts 02108
(617) 723-1774

PROFESSIONAL EXPERIENCE

President, PLC, Inc.
August 1986 - present

Consulting and testimony in utility and insurance economics. Reviewing utility supply planning processes and outcomes: assessing prudence of prior power planning investment decisions, identifying excess generating capacity, analyzing effects of power pool pricing rules on equity and utility incentives. Reviewing electric utility rate design. Estimating magnitude and cost of future load growth. Designing electric utility conservation programs, including hook-up charges.

Determining avoided costs due to cogenerators. Evaluating of cogeneration rate risk. Negotiating cogeneration contracts. Reviewing management and pricing of district heating system.

Determining fair profit margins for automobile and workers' compensation insurance lines, incorporating reward for risk, return on investments, and tax effects.

Research Associate, Analysis and Inference, Inc.
May, 1981 - August, 1986 (Consultant, 1980-1981)

Research, consulting and testimony 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.

Utility Rate Analyst, Massachusetts Attorney General
December, 1977 - May, 1981

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

S.M., Technology and Policy Program, Massachusetts Institute of Technology, February, 1978

S.B., Civil Engineering Department, Massachusetts Institute of Technology, June, 1974

HONORARY SOCIETIES

Chi Epsilon (Civil Engineering)
Tau Beta Pi (Engineering)
Sigma Xi (Research)

OTHER HONORS

Institute Award, Institute of Public Utilities, 1981

PUBLICATIONS

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

Chernick, P., "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 (in press).

PUBLICATIONS (CONTINUED)

Chernick, P., "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.

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

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

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

Chernick, P., "Opening the Utility Market to Conservation: A Competitive Approach," in 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.

Meyer, M., Chernick, P., and Fairley, W., "Insurance Market Assessment of Technological Risks," in Risk Analysis in the Private Sector, pp. 401-416, Plenum Press, New York, 1985.

Chernick, P., "Revenue Stability Target Ratemaking," Public Utilities Fortnightly, February 17, 1983, pp. 35-39.

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

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

Chernick, P., 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.

PRESENTATIONS

New England Utility Rate Forum; Plymouth, Massachusetts, October 11, 1985; "Lessons from Massachusetts on Long Term Rates for QF's".

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

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

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; "Insurance Market Assessment of Technological Risks".

EXPERT TESTIMONY

In each entry, the following information is presented in order: jurisdiction and docket number; title of case; client; date testimony filed; and subject matter covered. Abbreviations of jurisdictions include: MDPU (Massachusetts Department of Public Utilities); MEFSC (Massachusetts Energy Facilities Siting Council); PSC (Public Service Commission): and PUC (Public Utilities Commission).

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 S.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. Atomic Safety and Licensing Board, Nuclear Regulatory Commission 50-471; Pilgrim Unit 2, Boston Edison Company; Commonwealth of Massachusetts; June 29, 1979.

   Review of the Oak Ridge National Laboratory and the 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 cancelled 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, cogeneration, 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 forecast 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 DE81-312; 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 life, capacity factor), risks, discount rates, evaluation techniques.

24. New Mexico Public Service Commission 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, surplus flow, tax rates, and recognition of risk.

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; Mass. 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 proposal.

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 (QF's). 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 of return on investment for municipal utility. Treatment of depreciation and debt for ratemaking. Geographical discrimination in streetlighting 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 Public Service Commission 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.

Current need for power and cost-effectiveness of Millstone 3 for ratepayers. Identification of economically useful and useless investments. Ratemaking recommendations for generation planning penalty and for phase-in.

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 Public Service Commission 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 Public Service Commission 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 cashflows, 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 Public Service Commission 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 2 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.

APPENDIX B

DIRECT TESTIMONY OF

PAUL L. CHERNICK

on behalf of the

CONSERVATION LAW FOUNDATION

* * *

Scenario 1: No Charges to Participants

Table 1: Basic Inputs and Calculations

This table provides standard calculations of the cost of capital, return, and levelized capital recovery costs.

Capital Structure

		%	Cost	Wtd. Cost	38.3% Taxes	Wtd. Tax	Return + Taxes
1	Debt	40.0%	9.5%	3.8%		0.0%	3.8%
2	Preferred	50.0%	9.5%	4.8%	5.9%	2.9%	7.7%
3	Common	10.0%	12.0%	1.2%	7.4%	0.7%	1.9%
4	Total	100.0%		9.8% = CC		3.7%	13.4% = RT

	Life of Investment (years)	Levelized Capital Recovery Factor
5	5	28.56% = LVC5
6	10	18.41% = LVC10
7	15	15.34% = LVC15
8	20	14.02% = LVC20

Table 2(A): Program Description

Tables 2(A) and 2(B) take as inputs the avoided costs, conservation investment by life of measure, and annual GWH conservation by life of measure. From these inputs, levelized avoided costs and levelized program costs are computed. Lines 21-23 take as inputs the pre-program sales forecast and the projected participation rate, and compute the pre-program sales to participating customers.

1	Investment Year	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
2	Avoided Cost ¢/kWh	3.44	3.56	3.71	4.31	6.64	7.38	8.13	8.88	9.88	11.09	12.16	13.86	15.23	16.61	18.59	19.78
	15 yr measures																
3	$M invested	0.2	18.1	18.5	19.4	20.4	20.2	21.1	22.2	17.1	24.4	26.4	27.6	29.0	30.5	32.0	35.5
4	GWh saved/yr	0.0	64.6	64.6	64.6	64.6	59.4	59.4	59.4	59.4	59.4	61.4	61.4	61.4	61.4	61.4	66.6
5	Cents/kWh saved	*********	4.29	4.39	4.61	4.85	5.21	5.46	5.74	4.42	6.31	6.59	6.90	7.24	7.62	8.00	8.19
6	Utility share of program cost	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
7	Levelized A. C., ¢/kWh	8.72	9.81	11.05	12.41	13.65	14.99	16.42	17.95	19.59	21.33	22.21	22.99	23.69	24.31	24.76	25.10
8	Levelized A. C., $Mill	$0.0	$6.3	$7.1	$8.0	$8.8	$8.9	$9.7	$10.7	$11.6	$12.7	$13.6	$14.1	$14.6	$14.9	$15.2	$16.7
	20 yr measures																
9	$M invested	4.6	32.7	59.8	109.9	127.7	127.1	113.4	119.1	125.0	126.6	133.3	140.0	147.0	154.4	165.1	174.7
10	GWh saved/yr	10.9	93.9	169.5	309.4	341.1	325.6	289.6	289.6	289.6	282.7	284.1	284.1	284.1	284.1	298.4	301.7
11	cents/kWh saved	5.86	4.89	4.95	4.98	5.25	5.47	5.49	5.77	6.06	6.28	6.58	6.91	7.26	7.62	7.76	8.12
12	utility share of program cost	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
13	Levelized A. C., ¢/kWh	10.56	11.75	13.07	14.50	15.85	16.76	17.69	18.63	19.56	20.46	21.33	22.09	22.77	23.08	23.18	23.15
14	Levelized A. C., $Mill	$1.2	$11.0	$22.1	$44.9	$54.1	$54.6	$51.2	$53.9	$56.7	$57.8	$60.6	$62.8	$64.7	$65.6	$69.2	$69.9

Table 2(A):

		2004	2005	2006	2007	2008
1	Investment Year	2004	2005	2006	2007	2008
2	Avoided Cost ¢/kWh	21.94	24.02	26.18	27.70	30.01
	15 yr measures					
3	$M invested	8.4	8.8	9.2	9.8	10.6
4	GWh saved/yr	20.8	20.8	20.8	20.8	21.6
5	Cents/kWh saved	6.20	6.50	6.81	7.20	7.53
6	Utility share of program cost	100.0%	100.0%	100.0%	100.0%	100.0%
7	Levelized A. C., ¢/kWh	25.21	25.07	24.12	22.89	21.23
8	Levelized A. C., $Mill	$5.2	$5.2	$5.0	$4.8	$4.6
	20 yr measures					
9	$M invested	110.9	111.8	117.4	117.7	123.8
10	GWh saved/yr	271.3	255.0	206.3	183.0	116.3
11	cents/kWh saved	5.73	6.15	7.98	9.02	14.93
12	utility share of program cost	100.0%	100.0%	100.0%	100.0%	100.0%
13	Levelized A. C., ¢/kWh	22.88	22.34	21.49	20.39	18.91
14	Levelized A. C., $Mill	$62.1	$57.0	$44.3	$37.3	$22.0

Table 4(A):

1	Year:	2004	2005	2006	2007	2008	
	Energy Savings (GWH)						
2	15-yr measures	929	885	841	798	754	
3	20-yr measures	4,139	4,410	4,665	4,871	5,054	
4	Total	5,068	5,295	5,506	5,669	5,808	
	Sales w/ program						
5	Total	13,340	13,573	13,833	14,154	14,511	
6	% reduction	28%	28%	28%	29%	29%	
	% growth from 1988	0.5%	0.5%	0.6%	0.7%	0.8%	
7	Sales to Participants	15596	16193	16616	16996		← typo
8	% reduction	25%	25%	25%	25%		
9	MW Load Reduction @ load factor =	964	1,007	1,048	1,079	1,105	
	Levelized Program Costs ($ million)						Present Value @ Cost of Capital
10	15-yr measures	$55.6	$54.1	$52.7	$51.1	$49.5	
11	20-yr measures	$260.9	$276.5	$292.2	$308.6	$325.1	
12	Total	$316.5	$330.6	$344.8	$359.7	$374.6	$938.2

BECO Scenario 1 -- No Charges to Participants

Table 4(B): Annual Levelized Costs, Benefits, and Incentives

	Year:	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
	Levelized Avoided Costs (Program Benefits, $ million)																
13	15-yr measures		$0.0	$6.3	$13.5	$21.5	$30.3	$39.2	$49.0	$59.6	$71.3	$83.9	$98.2	$113.6	$130.3	$148.2	$167.5
14	20-yr measures		$1.2	$12.2	$34.3	$79.2	$133.3	$189.6	$244.3	$303.8	$368.4	$436.7	$510.8	$590.5	$675.8	$767.0	$868.8
15	Total		$1.2	$18.5	$47.8	$100.7	$163.6	$228.9	$293.3	$363.4	$439.7	$520.6	$609.0	$704.1	$806.1	$915.2	$1,036.3
16	Current Avoided Costs ($ million)		$0.4	$6.3	$17.4	$51.6	$87.3	$127.5	$170.2	$223.9	$290.0	$359.6	$457.8	$555.6	$663.4	$806.7	$929.5
	Lost Revenues																
17	/kWh		9.0	9.3	9.5	9.8	10.1	10.4	10.7	11.1	11.4	11.7	12.1	12.5	12.8	13.2	13.6
18	$ million		$1.0	$15.7	$38.5	$76.5	$119.9	$163.6	$206.0	$250.8	$298.1	$347.3	$399.5	$454.5	$512.5	$573.5	$639.7
	Net Social Benefits																
19	Levelized ($M)		$0.5	$10.5	$28.5	$63.0	$104.9	$149.3	$194.5	$244.6	$300.7	$360.1	$425.7	$496.9	$573.9	$656.7	$749.7
20	Current ($M)		($0.5)	($4.2)	($7.5)	$3.6	$13.5	$29.1	$50.7	$82.8	$128.4	$176.6	$252.9	$328.5	$413.6	$533.9	$632.7
21	Incentive Payment ($M) to Utility @ 10% of Levelized Benefit		$0.0	$1.0	$2.9	$6.3	$10.5	$14.9	$19.5	$24.5	$30.1	$36.0	$42.6	$49.7	$57.4	$65.7	$75.0
	Current Ratepayer Savings:																
22	($ million)		($0.5)	($5.3)	($10.3)	($2.7)	$3.0	$14.2	$31.3	$58.4	$98.3	$140.6	$210.3	$278.8	$356.2	$468.2	$557.7
23	/kWh (before program)		(0.0)	(0.0)	(0.1)	(0.0)	0.0	0.1	0.2	0.4	0.6	0.9	1.3	1.7	2.1	2.7	3.1

BECO Scenario 1 -- No Charges to Participants

Table 4(B):

	Year:	2004	2005	2006	2007	2008	Present Value @ Cost of Capital
	Levelized Avoided Costs (Program Benefits, $ million)						
13	15-yr measures	$189.9	$197.3	$205.3	$213.6	$222.5	
14	20-yr measures	$978.1	$1,081.9	$1,184.5	$1,271.4	$1,352.0	
15	Total	$1,168.0	$1,279.2	$1,389.7	$1,485.1	$1,574.5	$3,241.8
16	Current Avoided Costs ($ million)	$1,111.8	$1,271.9	$1,441.5	$1,570.2	$1,743.0	$2,697.4
	Lost Revenues						
17	/kWh	14.0	14.4	14.9	15.3	15.8	
18	$ million	$710.6	$764.7	$819.1	$868.6	$916.6	$2,076.5
	Net Social Benefits						
19	Levelized ($M)	$851.4	$948.6	$1,044.9	$1,125.3	$1,199.9	$2,303.7
20	Current ($M)	$789.9	$944.8	$1,109.7	$1,233.2	$1,401.4	$1,678.2
21	Incentive Payment ($M) to Utility @ 10% of Levelized Benefit	$85.1	$94.9	$104.5	$112.5	$120.0	$230.4
	Current Ratepayer Savings:						
22	($ million)	$704.7	$849.9	$1,005.2	$1,120.7	$1,281.4	$1,447.8
23	/kWh (before program)	3.8	4.5	5.2	5.7	6.3	

BECO Scenario 1 -- No Charges to Participants

Table 5: Costs Borne By Participants and Non-participants

Lines 2-4 compute the share of program costs charged to participants, assuming levelized financing by the utility or other party. Line 5 repeats the lost revenue line from Table 4. Lines 6-7 compute the share of lost revenues and net ratepayer savings distributed to participant through normal ratemaking. Line 8 computes current participant savings as lines 5+7 - lines 4+6. Line 10 assigns the remaining ratepayer benefits to non-participants. Lines 9 and 11 restate the effects on ratepayers in /kWh (for participants, the kWh used is that without the program).

		1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
1	Year	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
	Participant Share of Levelized Cost by Year Invested																
2	15-yr measures	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
3	20-yr measures	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
4	Costs Charged Participants		$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
5	Reduced Bills		$1.0	$15.7	$38.5	$76.5	$119.9	$163.6	$206.0	$250.8	$298.1	$347.3	$399.5	$454.5	$512.5	$573.5	$639.7
	Participant Share																
6	Lost Revenues		$0.0	$0.4	$1.9	$6.6	$14.2	$23.9	$34.9	$49.0	$65.9	$85.1	$107.9	$133.7	$163.0	$195.9	$234.4
7	Net Savings		($0.0)	($0.1)	($0.5)	($0.2)	$0.4	$2.1	$5.3	$11.4	$21.7	$34.5	$56.8	$82.0	$113.3	$159.9	$204.3
	Net Participant Benefits (current basis)																
8	$ million		$1.0	$15.2	$36.2	$69.7	$106.0	$141.8	$176.4	$213.2	$254.0	$296.6	$348.4	$402.8	$462.8	$537.6	$609.7
9	/kWh (before program)		0.3	1.9	2.4	3.0	3.5	3.8	4.0	4.2	4.4	4.6	4.9	5.2	5.5	5.9	6.2
	Non-participant Benefits (current basis)																
10	$ million		($1.5)	($20.5)	($46.5)	($72.4)	($103.0)	($127.6)	($145.1)	($154.9)	($155.7)	($156.0)	($138.1)	($124.0)	($106.6)	($69.4)	($52.0)
11	/kWh		(0.0)	(0.2)	(0.4)	(0.6)	(0.9)	(1.2)	(1.4)	(1.5)	(1.6)	(1.7)	(1.5)	(1.4)	(1.2)	(0.8)	(0.6)

BECO Scenario 1 -- No Charges to Participants

Table 5:

		2004	2005	2006	2007	2008	Present Value @ Cost of Capital
1	Year	2004	2005	2006	2007	2008	
	Participant Share of Levelized Cost by Year Invested						
2	15-yr measures	$0.0	$0.0	$0.0	$0.0	$0.0	
3	20-yr measures	$0.0	$0.0	$0.0	$0.0	$0.0	
4	Costs Charged Participant	$0.0	$0.0	$0.0	$0.0	$0.0	$0.0
5	Reduced Bills	$710.6	$764.7	$819.1	$868.6	$916.6	$2,076.5
	Participant Share						
6	Lost Revenues	$278.1	$301.8	$328.8	$348.8	$366.8	$617.7
7	Net Savings	$275.8	$335.4	$403.5	$450.0	$512.8	$519.8
	Net Participant Benefits (current basis)						
8	$ million	$708.3	$798.3	$893.8	$969.8	$1,062.6	$1,978.6
9	/kWh (before program)	6.9	7.4	8.1	8.6	9.2	
	Non-participant Benefits (current basis)						
10	$ million	($3.5)	$51.6	$111.4	$150.9	$218.9	($530.8)
11	/kWh	(0.0)	0.6	1.3	1.8	1.5	

APPENDIX C

DIRECT TESTIMONY OF

PAUL L. CHERNICK

on behalf of the

CONSERVATION LAW FOUNDATION

* * *

Scenario 2: 20% Charged to Participants

Table 1: Basic Inputs and Calculations

This table provides standard calculations of the cost of capital, return, and levelized capital recovery costs.

	Capital Structure %	Cost	Wtd. Cost	38.3% Taxes	Wtd. Tax	Return + Taxes
1 Debt	40.0%	9.5%	3.8%		0.0%	3.8%
2 Preferred	50.0%	9.5%	4.8%	5.9%	2.9%	7.7%
3 Common	10.0%	12.0%	1.2%	7.4%	0.7%	1.9%
4 Total	100.0%		9.8% = CC		3.7%	13.4% = RT

	Life of Investment (years)	Levelized Capital Recovery Factor
5	5	28.56% = LVC5
6	10	18.41% = LVC10
7	15	15.34% = LVC15
8	20	14.02% = LVC20

BECO Scenario 2 -- 20% Charged to Participants

Table 2(A): Program Description

Tables 2(A) and 2(B) take as inputs the avoided costs, conservation investment by life of measure, and annual GWH conservation by life of measure. From these inputs, levelized avoided costs and levelized program costs are computed. Lines 21-23 take as inputs the pre-program sales forecast and the projected participation rate, and compute the pre-program sales to participating customers.

1 Investment Year	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
2 Avoided Cost /kWh	3.44	3.56	3.71	4.31	6.64	7.38	8.13	8.88	9.88	11.09	12.16	13.86	15.23	16.61	18.59	19.78
15 yr measures																
3 $M invested	0.2	18.1	18.5	19.4	20.4	20.2	21.1	22.2	17.1	24.4	26.4	27.6	29.0	30.5	32.0	35.5
4 GWh saved/yr	0.0	64.6	64.6	64.6	64.6	59.4	59.4	59.4	59.4	59.4	61.4	61.4	61.4	61.4	61.4	66.6
5 Cents/kWh saved	*********	4.29	4.39	4.61	4.85	5.21	5.46	5.74	4.42	6.31	6.59	6.90	7.24	7.62	8.00	8.19
6 Utility share of program cost	80.0%	80.0%	80.0%	80.0%	80.0%	80.0%	80.0%	80.0%	80.0%	80.0%	80.0%	80.0%	80.0%	80.0%	80.0%	80.0%
7 Levelized A. C., /kWh	8.72	9.81	11.05	12.41	13.65	14.99	16.42	17.95	19.59	21.33	23.19	25.11	27.13	29.24	31.37	33.61
8 Levelized A. C., $Mill	$0.0	$6.3	$7.1	$8.0	$8.8	$8.9	$9.7	$10.7	$11.6	$12.7	$14.2	$15.4	$16.7	$18.0	$19.3	$22.4
20 yr measures																
9 $M invested	4.6	32.7	59.8	109.9	127.7	127.1	113.4	119.1	125.0	126.6	133.3	140.0	147.0	154.4	165.1	174.7
10 GWh saved/yr	10.9	93.9	169.5	309.4	341.1	325.6	289.6	289.6	289.6	282.7	284.1	284.1	284.1	284.1	298.4	301.7
11 cents/kWh saved	5.86	4.89	4.95	4.98	5.25	5.47	5.49	5.77	6.06	6.28	6.58	6.91	7.26	7.62	7.76	8.12
12 utility share of program cost	80.0%	80.0%	80.0%	80.0%	80.0%	80.0%	80.0%	80.0%	80.0%	80.0%	80.0%	80.0%	80.0%	80.0%	80.0%	80.0%
13 Levelized A. C., /kWh	10.56	11.75	13.07	14.50	15.85	17.31	18.87	20.55	22.32	24.16	26.09	28.04	30.04	32.09	34.12	36.21
14 Levelized A. C., $Mill	$1.2	$11.0	$22.1	$44.9	$54.1	$56.4	$54.7	$59.5	$64.6	$68.3	$74.1	$79.7	$85.3	$91.2	$101.8	$109.3

Table 2(A):

1	Investment Year	2004	2005	2006	2007	2008
2	Avoided Cost /kWh	21.94	24.02	26.18	27.70	30.01
	15 yr measures					
3	$M invested	8.4	8.8	9.2	9.8	10.6
4	GWh saved/yr	20.8	20.8	20.8	20.8	21.6
5	Cents/kWh saved	6.20	6.50	6.81	7.20	7.53
6	Utility share of program cost	80.0%	80.0%	80.0%	80.0%	80.0%
7	Levelized A. C., /kWh	35.84	38.05	40.23	42.44	44.57
8	Levelized A. C., $Mill	$7.5	$7.9	$8.4	$8.8	$9.6
	20 yr measures					
9	$M invested	110.9	111.8	117.4	117.7	123.8
10	GWh saved/yr	271.3	255.0	206.3	183.0	116.3
11	cents/kWh saved	5.73	6.15	7.98	9.02	14.93
12	utility share of program cost	80.0%	80.0%	80.0%	80.0%	80.0%
13	Levelized A. C., /kWh	38.25	40.24	42.14	44.03	45.82
14	Levelized A. C., $Mill	$103.8	$102.6	$86.9	$80.6	$53.3

BECO Scenario 2 -- 20% Charged to Participants

Table 2(B):

	Investment Year	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
	Total																
15	$M invested	$4.8	$50.8	$78.3	$129.3	$148.1	$147.2	$134.6	$141.3	$142.1	$151.0	$159.7	$167.6	$176.0	$184.9	$197.2	$210.2
16	MWh saved/yr	10.9	158.5	234.1	374.0	405.8	385.0	349.0	349.0	349.0	342.0	345.6	345.6	345.6	345.6	359.8	368.3
17	Cents/kWh saved	6.19	4.65	4.79	4.92	5.18	5.43	5.49	5.76	5.78	6.29	6.58	6.91	7.25	7.62	7.80	8.13
18	Utility share of program cost	80.0%	80.0%	80.0%	80.0%	80.0%	80.0%	80.0%	80.0%	80.0%	80.0%	80.0%	80.0%	80.0%	80.0%	80.0%	80.0%
19	Levelized A. C., /kWh	10.56	10.96	12.51	14.14	15.50	16.95	18.45	20.11	21.85	23.67	25.57	27.52	29.52	31.58	33.65	35.74
20	Levelized A. C., $Mill	$1.2	$17.4	$29.3	$52.9	$62.9	$65.3	$64.4	$70.2	$76.3	$81.0	$88.4	$95.1	$102.0	$109.1	$121.1	$131.6
	Participation																
21	Total GWh sales w/o program	12,400	12,710	13,028	13,353	13,687	14,029	14,380	14,740	15,108	15,486	15,873	16,270	16,677	17,094	17,521	17,959
22	Percent growth since 1988		2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
23	% of Customers Participating	0%	3%	6%	11%	17%	22%	26%	30%	34%	37%	41%	44%	47%	50%	52%	55%
24	Participating Customer Sales	21	331	787	1,517	2,309	3,060	3,741	4,422	5,103	5,770	6,444	7,119	7,793	8,467	9,169	9,888

Table 2(B):

	Investment Year	2004	2005	2006	2007	2008
	Total					
15	$M invested	$119.3	$120.6	$126.6	$127.4	$134.4
16	MWh saved/yr	292.1	275.8	227.1	203.8	137.9
17	Cents/kWh saved	5.77	6.18	7.87	8.83	13.77
18	Utility share of program cost	80.0%	80.0%	80.0%	80.0%	80.0%
19	Levelized A. C., /kWh	38.08	40.07	41.97	43.87	45.62
20	Levelized A. C., $Mill	$111.2	$110.5	$95.3	$89.4	$62.9
	Participation					
21	Total GWh sales w/o program	18,408	18,868	19,340	19,823	20,319
22	Percent growth since 1988	2.5%	2.5%	2.5%	2.5%	2.5%
23	% of Customers Participating	56%	57%	57%	57%	57%
24	Participating Customer Sales	10,332	10,744	11,061	11,333	11,582

Table 3: Annual Cost to Ratepayers

BECO Scenario 2 -- 20% Charged to Participants

	1 Yr Cost Recovered	2004	2005	2006	2007	2008	Present Value @ Cost of Capital
	15 year measures						
2	Additions	$6.7	$7.1	$7.4	$7.8	$8.5	
3	Depreciation	$19.3	$18.8	$18.3	$17.8	$17.2	
4	Ratebase	$159.6	$147.8	$136.9	$127.0	$118.2	
5	Return & taxes	$23.1	$21.4	$19.9	$18.4	$17.1	
6	Cost recovery	$42.5	$40.3	$38.2	$36.2	$34.3	$137.3
	20 year measures						
7	Additions	$88.7	$89.5	$93.9	$94.1	$99.0	
8	Depreciation	$74.4	$78.9	$83.3	$88.0	$92.7	
9	Ratebase	$1,060.7	$1,071.3	$1,081.9	$1,088.0	$1,094.4	
10	Return & taxes	$140.7	$142.6	$144.0	$145.4	$146.3	
11	Cost recovery	$215.1	$221.4	$227.3	$233.5	$239.0	$678.1
	Totals						
12	Additions	$95.4	$96.5	$101.3	$101.9	$107.5	
13	Depreciation	$93.7	$97.7	$101.6	$105.8	$109.9	
14	Ratebase	$1,220.3	$1,219.1	$1,218.8	$1,215.0	$1,212.6	
15	Return & taxes	$163.8	$164.0	$163.9	$163.8	$163.3	
16	Cost recovery	$257.6	$261.7	$265.5	$269.6	$273.2	$815.4

Table 4(A): Annual Levelized Costs, Benefits, and Incentives

Energy savings from Table 2 are repeated on lines 2-4. Lines 5 & 7 calculate sales with the program, both for the entire utility and for the participants, and lines 6 & 8 compute the % reduction in sales due to the program. Line 9 converts the energy savings to MW savings. Levelized program costs are computed (lines 10-12), as are levelized and current benefits (lines 13-15). A /kWh value for lost revenues is input to line line 17, and total lost revenues calculated. Net social benefits are calculated as the difference between previously calculated benefits and costs, on both levelized (line 10 - line 12 and current (line 12 - line 26, Table 3). The utility incentive payment is calculated as a % of line 19, and the remaining ratepayer savings are computed. The ratepayer savings are converted to /kWh, based on the sales prior to the conservation program.

		1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
1	Year:	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
	Energy Savings (GWH)																
2	15-yr measures		0	65	129	194	258	318	377	437	496	555	617	678	740	801	863
3	20-yr measures		11	105	274	584	925	1,250	1,540	1,830	2,119	2,402	2,686	2,970	3,254	3,538	3,837
4	Total		11	169	404	777	1,183	1,568	1,917	2,266	2,615	2,957	3,303	3,648	3,994	4,339	4,699
	Sales w/ program																
5	Total	12,400	12,699	12,858	12,950	12,910	12,846	12,812	12,823	12,842	12,871	12,916	12,967	13,028	13,100	13,181	13,260
6	% reduction		0%	1%	3%	6%	8%	11%	13%	15%	17%	19%	20%	22%	23%	25%	26%
	% growth from 1988		2.4%	1.8%	1.5%	1.0%	0.7%	0.5%	0.5%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%
7	Sales to Participants	21	320	618	1114	1531	1877	2173	2505	2836	3155	3487	3816	4145	4473	4830	5189
8	% reduction		3%	22%	27%	34%	39%	42%	43%	44%	45%	46%	46%	47%	47%	47%	48%
9	MW Load Reduction @ load factor =	60%	2	32	77	148	225	298	365	431	498	563	628	694	760	826	894
	Levelized Program Costs ($ million)																
10	15-yr measures		$0.0	$2.8	$5.6	$8.6	$11.8	$14.9	$18.1	$21.5	$24.1	$27.9	$31.9	$36.2	$40.6	$45.3	$50.2
11	20-yr measures		$0.6	$5.2	$13.6	$29.0	$46.9	$64.7	$80.7	$97.4	$114.9	$132.6	$151.3	$171.0	$191.6	$213.3	$236.4
12	Total		$0.7	$8.0	$19.3	$37.7	$58.7	$79.6	$98.8	$118.9	$139.0	$160.5	$183.3	$207.1	$232.2	$258.5	$286.6

Table 4(A):

1	Year:	2004	2005	2006	2007	2008	
	Energy Savings (GWH)						
2	15-yr measures	929	885	841	798	754	
3	20-yr measures	4,139	4,410	4,665	4,871	5,054	
4	Total	5,068	5,295	5,506	5,669	5,808	
	Sales w/ program						
5	Total	13,340	13,573	13,833	14,154	14,511	
6	% reduction	28%	28%	28%	29%	29%	
	% growth from 1988	0.5%	0.5%	0.6%	0.7%	0.8%	
7	Sales to Participants	5264	5449	5555	5664		
8	% reduction	49%	49%	50%	50%		
9	MW Load Reduction @ load factor =	964	1,007	1,048	1,079	1,105	
	Levelized Program Costs ($ million)						Present Value @ Cost of Capital
10	15-yr measures	$55.6	$54.1	$52.7	$51.1	$49.5	
11	20-yr measures	$260.9	$276.5	$292.2	$308.6	$325.1	
12	Total	$316.5	$330.6	$344.8	$359.7	$374.6	$938.2

Table 4(B): Annual Levelized Costs, Benefits, and Incentives

	Year:	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
	Levelized Avoided Costs (Program Benefits, $ million)																
13	15-yr measures		$0.0	$6.3	$13.5	$21.5	$30.3	$39.2	$49.0	$59.6	$71.3	$83.9	$98.2	$113.6	$130.3	$148.2	$167.5
14	20-yr measures		$1.2	$12.2	$34.3	$79.2	$133.3	$189.6	$244.3	$303.8	$368.4	$436.7	$510.8	$590.5	$675.8	$767.0	$868.8
15	Total		$1.2	$18.5	$47.8	$100.7	$163.6	$228.9	$293.3	$363.4	$439.7	$520.6	$609.0	$704.1	$806.1	$915.2	$1,036.3
16	Current Avoided Costs ($ million)		$0.4	$6.3	$17.4	$51.6	$87.3	$127.5	$170.2	$223.9	$290.0	$359.6	$457.8	$555.6	$663.4	$806.7	$929.5
	Lost Revenues																
17	/kWh		9.0	9.3	9.5	9.8	10.1	10.4	10.7	11.1	11.4	11.7	12.1	12.5	12.8	13.2	13.6
18	$ million		$1.0	$15.7	$38.5	$76.5	$119.9	$163.6	$206.0	$250.8	$298.1	$347.3	$399.5	$454.5	$512.5	$573.5	$639.7
	Net Social Benefits																
19	Levelized ($M)		$0.5	$10.5	$28.5	$63.0	$104.9	$149.3	$194.5	$244.6	$300.7	$360.1	$425.7	$496.9	$573.9	$656.7	$749.7
20	Current ($M)		($0.5)	($3.7)	($6.3)	$5.7	$16.6	$32.9	$54.9	$87.3	$132.9	$181.1	$257.2	$332.5	$417.1	$536.7	$634.7
21	Incentive Payment ($M) to Utility @ 10% of Levelized Benefit		$0.0	$1.0	$2.9	$6.3	$10.5	$14.9	$19.5	$24.5	$30.1	$36.0	$42.6	$49.7	$57.4	$65.7	$75.0
	Current Ratepayer Savings:																
22	($ million)		($0.5)	($4.8)	($9.2)	($0.6)	$6.1	$18.0	$35.4	$62.8	$102.8	$145.1	$214.6	$282.8	$359.7	$471.1	$559.7
23	/kWh (before program)		(0.0)	(0.0)	(0.1)	(0.0)	0.0	0.1	0.2	0.4	0.7	0.9	1.3	1.7	2.1	2.7	3.1

Table 4(B):

	Year:	2004	2005	2006	2007	2008	Present Value @ Cost of Capital
	Levelized Avoided Costs (Program Benefits, $ million)						
13	15-yr measures	$189.9	$197.3	$205.3	$213.6	$222.5	
14	20-yr measures	$978.1	$1,081.9	$1,184.5	$1,271.4	$1,352.0	
15	Total	$1,168.0	$1,279.2	$1,389.7	$1,485.1	$1,574.5	$3,241.8
16	Current Avoided Costs ($ million)	$1,111.8	$1,271.9	$1,441.5	$1,570.2	$1,743.0	$2,697.4
	Lost Revenues						
17	/kWh	14.0	14.4	14.9	15.3	15.8	
18	$ million	$710.6	$764.7	$819.1	$868.6	$916.6	$2,076.5
	Net Social Benefits						
19	Levelized ($M)	$851.4	$948.6	$1,044.9	$1,125.3	$1,199.9	$2,303.7
20	Current ($M)	$791.0	$944.1	$1,107.1	$1,228.7	$1,394.8	$1,694.4
	Incentive Payment ($M) to Utility @ 10%						
21	of Levelized Benefit	$85.1	$94.9	$104.5	$112.5	$120.0	$230.4
	Current Ratepayer Savings:						
22	($ million)	$705.8	$849.2	$1,002.6	$1,116.2	$1,274.8	$1,464.0
23	/kWh (before program)	3.8	4.5	5.2	5.6	6.3	

BECO Scenario 2 -- 20% Charged to Participants

Table 5: Costs Borne By Participants and Non-participants

Lines 2-4 compute the share of program costs charged to participants, assuming levelized financing by the utility or other party. Line 5 repeats the lost revenue line from Table 4. Lines 6-7 compute the share of lost revenues and net ratepayer savings distributed to participant through normal ratemaking. Line 8 computes current participant savings as lines 5+7 - lines 4+6. Line 10 assigns the remaining ratepayer benefits to non-participants. Lines 9 and 11 restate the effects on ratepayers in /kWh (for participants, the kWh used is that without the program).

		1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
1	Year	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
	Participant Share of Levelized Cost by Year Invested																
2	15-yr measures	$0.0	$0.6	$0.6	$0.6	$0.6	$0.6	$0.6	$0.7	$0.5	$0.7	$0.8	$0.8	$0.9	$0.9	$1.0	$1.1
3	20-yr measures	$0.1	$0.9	$1.7	$3.1	$3.6	$3.6	$3.2	$3.3	$3.5	$3.6	$3.7	$3.9	$4.1	$4.3	$4.6	$4.9
4	Costs Charged Participants		$0.1	$1.6	$3.9	$7.5	$11.7	$15.9	$19.8	$23.8	$27.8	$32.1	$36.7	$41.4	$46.4	$51.7	$57.3
5	Reduced Bills		$1.0	$15.7	$38.5	$76.5	$119.9	$163.6	$206.0	$250.8	$298.1	$347.3	$399.5	$454.5	$512.5	$573.5	$639.7
	Participant Share																
6	Lost Revenues		$0.0	$0.4	$1.9	$6.6	$14.2	$23.9	$34.9	$49.0	$65.9	$85.1	$107.9	$133.7	$163.0	$195.9	$234.4
7	Net Savings		($0.0)	($0.1)	($0.4)	($0.1)	$0.7	$2.6	$6.0	$12.3	$22.7	$35.6	$57.9	$83.2	$114.4	$160.9	$205.1
	Net Participant Benefits (current basis)																
8	$ million		$0.8	$13.6	$32.4	$62.3	$94.6	$126.4	$157.3	$190.3	$227.2	$265.6	$312.9	$362.5	$417.4	$486.8	$553.1
9	/kWh (before program)		0.3	1.7	2.1	2.7	3.1	3.4	3.6	3.7	3.9	4.1	4.4	4.7	4.9	5.3	5.6
	Non-participant Benefits (current basis)																
10	$ million		($1.3)	($18.4)	($41.6)	($62.9)	($88.6)	($108.4)	($121.9)	($127.5)	($124.4)	($120.5)	($98.3)	($79.7)	($57.7)	($15.8)	$6.6
11	/kWh		(0.0)	(0.2)	(0.4)	(0.6)	(0.8)	(1.0)	(1.2)	(1.3)	(1.3)	(1.3)	(1.1)	(0.9)	(0.7)	(0.2)	0.1

Table 5:

		2004	2005	2006	2007	2008	Present Value @ Cost of Capital
1	Year	2004	2005	2006	2007	2008	
	Participant Share of Levelized Cost by Year Invested						
2	15-yr measures	$0.3	$0.3	$0.3	$0.3	$0.3	
3	20-yr measures	$3.1	$3.1	$3.3	$3.3	$3.5	
4	Costs Charged Participant	$63.3	$66.1	$69.0	$71.9	$74.9	$187.6
5	Reduced Bills	$710.6	$764.7	$819.1	$868.6	$916.6	$2,076.5
	Participant Share						
6	Lost Revenues	$278.1	$301.8	$328.8	$348.8	$366.8	$617.7
7	Net Savings	$276.2	$335.1	$402.5	$448.2	$510.1	$522.6
	Net Participant Benefits (current basis)						
8	$ million	$645.4	$731.9	$823.8	$896.0	$985.0	$1,793.8
9	/kWh (before program)	6.2	6.8	7.4	7.9	8.5	
	Non-participant Benefits (current basis)						
10	$ million	$60.4	$117.3	$178.8	$220.1	$289.8	($329.7)
11	/kWh	0.7	1.4	2.2	2.6	2.0	

APPENDIX D

DIRECT TESTIMONY OF

PAUL L. CHERNICK

on behalf of the

CONSERVATION LAW FOUNDATION

* * *

Revenue Stability Target Rate Making
by Paul L. Chernick

Revenue Stability Target Rate Making

By PAUL L. CHERNICK

The commonly used rate-making approaches necessarily base themselves on assumptions, vital to their success, about future levels of utility service sales. But since sales are a function of random variables beyond the control of the utility as well as actions by the utility itself, the resulting rates fail to protect the utility's revenue stream and its realized rate of return. This article proposes an alternative approach which would decouple utility revenues from sales, thus stabilizing revenue streams with respect to sales fluctuations and rate design changes. Among the benefits would be a lower cost of capital for the utility, as well as decreased utility resistance to conservation by consumers and to efficient rate design.

TRADITIONAL utility rate-making procedures result in orders allowing specific rate levels and rate designs. These rates are expected to allow the utility to generate the required revenue. Because this rate-making approach does not recognize that sales are a function both of the utility's actions and of such random variables as weather, the resultant rates discourage utility conservation efforts, fail to protect the utility's revenue stream, increase required rates of return, and alternately produce overcollections and undercollections. Uncertainty is increased by the transition to new rates, such as time-of-use and inverted block rates.

This article suggests an alternative rate-making scheme, which decouples utility revenues from sales. Utility revenue streams would be stabilized, at least with respect to sales fluctuations and rate design changes: Thus, the cost of capital should decrease to the ultimate benefit of the customers. Utility resistance to consumers' conservation and to efficient rate design should also decrease. The proposed approach would be readily compatible with utility financing of conservation programs; with cost indexing; with marginal cost pricing; with other innovative rate designs whose effects are not well known; and with tax relief proposals.

The article consists of four sections, other than this introduction. The first describes the pertinent aspects of current rate making, and enumerates the problems which result from current practice. The second outlines an alternative proposal, which I call revenue stability target rate making (RSTR). The third discusses the advantages and opportunities afforded by RSTR, while the fourth describes some of the possible drawbacks to this approach.

Paul L. Chernick is a research associate with Analysis and Inference, Inc., in Boston, Massachusetts, where his research and consulting work relates to various aspects of electric utility regulation, including rate design, cost allocation, load forecasting, capacity planning, and efficiency incentives. **Mr. Chernick** received an SM degree in technology and policy and an SB degree from the Massachusetts Institute of Technology. He has co-authored a report for the Nuclear Regulatory Commission on insurance for nuclear decommissioning.

Current Rate-making Procedures

In general, utility rates are set in a three-step process. First, the total revenue target, T, is set as the sum of all allowed expenses (including operations and maintenance, return, depreciation, and taxes). Second, the allowed revenues are allocated to the various customer classes to establish class revenue constraints, t_i, where

$$\sum_i t_i = T. \qquad (1)$$

Finally, for each class a set of rates (r_j) is approved, so that

$$\sum_j r_j\, b_{ij} = t_i \qquad (2)$$

where b_{ij} is the anticipated number of billing units in class i to which rate j is applicable. Examples of billing units would include customer-months, kilowatt-hours, and kilowatts, perhaps distinguished by subclass, block, and other special provisions; e.g., high-load factor or high-voltage discounts.

It is the r_j which is ultimately approved in a typical rate proceeding, and the final order grants the utility new rates, which are based upon (but not identical to) the revenue target. If the calculations have been performed properly, and if the actual billing units ($b^{\bullet}_{ij}$) in the rate year exactly equal the b_{ij} used in Equation 2 in the rate case, then

$$\sum_i \sum_j r_j b^{\bullet}_{ij} = T, \qquad (3)$$

and the utility collects exactly the amount of revenue the regulatory commission expected it to collect.[1]

In fact, actual billing units hardly ever equal anticipated billing units. Several factors contribute to this divergence, including:

- economic fluctuations, which affect the level of industrial production, of commercial activities, and of new equipment and appliance purchases, as well as the care with which energy budgets are controlled;
- actions of large customers, such as faster (or slower) completion of new facilities or housing complexes, relocation of operations, or changes in technology;
- the weather, which has major effects on heating and air-conditioning usage, with smaller effects on several other energy uses;
- conservation (or consumption) caused by price changes (including the ones allowed in this case), and by conservation and fuel switching programs of governmental bodies and of the utility itself;
- the rate-making process may be based on an historic test year, and thus may use historic values of billing units, rather than the best available projections of those values; and
- rate design changes, which may introduce billing units for which even current values are unknown — e.g., off-peak kilowatt-hour, residential noncoincident demand — and which may cause significant shifts in consumption patterns; e.g., changes in use by time of day, or by block, or in load factor.

Two major problems result from the divergence of actual from anticipated billing units. First, there is no assurance that the utility will actually receive the revenues, T, which the commission has approved. In fact, it is quite unlikely that Equation 3 will be exactly satisfied. Some years will produce revenues lower than T, while other years will produce revenues higher than T. The variation of actual revenues, around the level of allowed revenues, creates difficulty for the utility in budgeting, both for operations and for capital investment.[2] More importantly, the variability in earnings[3] is five to ten times greater than the variability in revenues. Earnings (E) are the residual after expenses, interest, and preferred dividends (which I will collectively call X) are subtracted from revenues:

$$E = \sum_i \sum_j r_j b^{\bullet}_{ij} - X. \qquad (4)$$

Earnings are typically about 10 per cent of revenues. Income taxes are approximately equal to earnings (at least at the margin) and vary directly with them. Thus, if earnings are 10 per cent of revenues, both earnings and income taxes would be eliminated by a 20 per cent decrease in revenues, with expenses and other charges held constant.[4]

While the reliability of earnings is directly important to shareholders, it is also significant for ratepayers. Earnings variability, particularly when positively correlated with changes in the general economic environment,[5] increases the required return on common equity, and hence the cost of utility service.

In addition to the direct effects on the utility and its cost of capital, the dependence of cash flow and earnings on billing units also causes utilities to engage in undesirable, but understandable, behavior. One typical utility response is to attempt to maintain or increase billing units in the short run: No matter what set of rates are approved, the utility will be better off in the short run — i.e., while these rates are in effect — with higher sales than with lower sales. Thus, utilities are generally uninterested in rate reform, which may have large impact within a short period of time. Even if the b_{ij} values used in rate setting are reduced (and hence the r_j are increased) to reflect the anticipated effect of a conservation program, it still is in the utility's self-interest to delay the program, and promote sales. Earnings are positively and directly related to sales, regardless of the rates granted.

The second utility response to the current rate-making system is a preference for recovering revenues through charges on those billing units which are less responsive to customers' behavior. In this regard, the ideal billing unit is the take-or-pay contract. A close second choice is the monthly customer charge, which will always be assessed so long as the customer remains on the system. Ratcheted demand charges[6] and the inner blocks of energy and demand schedules are also less responsive to customer consumption patterns than are normal monthly charges or the marginal energy or demand block. Unfortunately, the billing units which are most desirable for revenue stability are least desirable for efficiency purposes, particularly when marginal costs exceed average costs.

[1]This is a separate question from whether the utility makes its allowed rate of return, which is a function of expenses, as well as revenues.

[2]The importance of the budgeting effect is reduced for most utilities by their access to extensive short-term bank credit. However, in extreme cases, revenue variation may induce a utility to defer otherwise cost-effective maintenance, may require the issuance of securities at inopportune times, and may even require (by invoking interest coverage constraints) the issuance of less desirable securities.

[3]Earnings are the sum of dividends and retained earnings, and represent the total funds available to compensate the shareholders.

[4]In fact, some expenses (primarily fuel) vary with the b_{ij} (primarily kilowatt-hours).

[5]This correlation is commonly reported as the beta coefficient.

[6]Ratcheted demand charges set the billing unit as the maximum of demand in the current month and a fraction (possibly 100 per cent) of demand in a previous time period (often a year).

Consumer behavior is unlikely to be affected by charges which are independent of that behavior. For example, the size of the residential electric customer charge and of the innermost energy blocks — e.g., 0-50 kilowatt-hours per month — are unlikely to influence consumption and conservation decisions: Very few residences will be able to avoid either of these charges, and few will attempt to do so, regardless of the size of the charges. The tailblock energy charges, on the other hand, are very potent price signals, since a customer who uses one more (or less) kilowatt-hour will pay (or save) the tailblock rate.[7] But by the same token, tailblock sales are more volatile than those from the inner blocks and customer charges, and hence less desirable for revenue stability purposes.

A third rational, but undesirable, utility tactic in maintaining revenue stability is the avoidance of rate design changes. Shifting revenue responsibility from demand charges to energy charges, or instituting time-differentiated rates, may not increase the long-term instability of revenues, but may produce great uncertainty in the short term. The test-year number of billing units may be unknown (especially for new time-differentiated rates), and the response of consumers may be very hard to estimate. Thus, next year's revenues are more secure if the rate structure remains largely unchanged.

The previous discussion has established that the current rate-setting process increases the riskiness and cost of utility equity; discourages utility participation in conservation and rate redesign; and encourages sales promotion and inefficient price signals. There is certainly room for improvement in the system: The next question is whether any such improvement is administratively feasible.

Redesigning the Rate-making Process To Promote Revenue Stability

Stabilizing utility revenues and eliminating the existing perverse incentives for utility management require a fundamental change in the nature of regulatory commission rate orders. Rather than approving a set of rates (r_j) which are *expected* to produce the allowed revenues (T), the commission must approve the revenue level itself, as well as a mechanism for maintaining those revenues with a fair degree of certainty. The rates to be charged immediately following the effective date of the order are part of that mechanism, but are not generally sufficient in themselves, as noted above.

Revenue stability target rate making (RSTR or ReSToRe) would establish two separate total dollar amounts: the target revenues (T) to the utility; and a larger sum, the estimated collections (C) from the customers. A set of rates (r_j) would be established so that

$$\Sigma_i \Sigma_j \, r_j \, b_{ij} = C. \tag{5}$$

If actual billing units equal the b_{ij}, the utility will collect C from its customers, but only T will be counted as revenues to the utility. The remainder, a buffer B (= C − T), is the customers' money held in trust by the utility. The buffer, and associated interest at market rates, may be returned to the customers in several ways, to be discussed in the next section.

If sales are below expectation ($b^* < b$), the buffer will be smaller than expected: The utility still receives T, and less money is accumulated to be returned to the customers. So long as ratio of actual to forecast billing units, b^*/b (averaged over the b_{ij} in proportion to expected revenues), is higher than T/C, the utility is guaranteed to receive its full allowed revenues, but no more than allowed revenues. Since some of the billing units (especially customer-months) may be very stable, a buffer of 5 per cent of allowed revenues should provide substantial revenue security to the utility.

The expected buffer, B, may be apportioned to classes, rates, and billing units, in proportion to allocated revenues, or so as to bring rates closer to marginal costs or other rate design targets. Similarly, the actual buffer, B^*, may be returned to the customers as a whole, or to the customer classes in proportion to their contribution to B or B^*.

For many utilities, fuel costs are collected through an adjustment process which tracks costs closely and essentially guarantees full recovery. For these utilities, RSTR can be applied to just the base (nonfuel) rates, and

$$T = N + A \tag{6}$$

where N is nonfuel costs and A is actual fuel costs (collected through the fuel clause). For utilities without fuel clauses (generally those with fairly stable fuel costs), RSTR can be structured as

$$T = N + E + M\,(S^* - S) \tag{7}$$

where E is expected energy costs, M is the marginal cost of energy (over reasonable variations in sales), and S and S^* are expected and actual kilowatt-hour output. Thus, if sales increase, the revenue target rises to cover the associated increase in fuel expense.[8]

Some Advantages of RSTR

RSTR should directly correct several of the problems discussed in the early part of this article. Utility resistance to conservation programs (and rate reform) should

[7]The block which serves as the tailblock will vary between customers. In general, however, a higher percentage of the kilowatt-hours sold in a higher-use block will be sold to customers of whom that block is the tailblock than would be true for lower-use blocks. Of course, all customers who consume in the final block of the rate schedule have that as their tailblock.

[8]A similar, but more limited, approach was suggested in 1979 rate design testimony by the author and Susan C. Geller on behalf of the Massachusetts attorney general (MDPU 19845). Due to the uncertainty in the time-of-use billing determinant, we suggested a form of RSTR in which *T* is the revenues which would have been collected under conventional rates at the actual billing determinants. Hence, both the utilities and the customers are protected from errors in billing determinant estimates and from the load shifting induced by the rate design change.

decrease, utility earnings should stabilize (and particularly become less weather-sensitive), the cost of equity should decline, and rate redesign will have less impact on utility revenues. The buffer can also be collected so as to bring energy charges closer to marginal costs within embedded-cost revenue constraints.

The size of the actual buffer can be controlled in several ways. In a revenue-neutral approach, the size of the buffer at the time of each rate case would determine the provision for replenishing the buffer in the new rates. If the buffer were small, C would be set well above T, to continue (or even accelerate) the accumulation of a buffer. If the buffer is sufficiently large, C would be set equal to T, so that accumulation stops. And if a series of years with bad weather and good economic activity create an unnecessarily large buffer, it can be drawn down by applying the interest and a portion of the principal to the rate-year cost of service.

The basic alternative to a revenue-neutral approach is a process of continuous targeted buffer accumulation, with the surplus (when sales create one) returned to the customers or used for their benefit. For example, the accumulated funds can be directed to financing conservation programs, with the convenient feature that available funds increase when increasing loads make conservation particularly desirable. The buffer can alternatively be distributed to local governments to offset property taxes (perhaps in proportion to sales by class and by municipality), meeting a major social concern.

The buffer can also be used to stabilize rates and to reduce the frequency of rate increase requests. Directly, RSTR would reduce the need for rate increases to compensate for falling sales. Indirectly, the accumulated funds may be used to pay for small revenue increases to the utility, without changing rates paid by customers. For example, the commission could allow an increase in property taxes to be paid from the buffer. Similarly, if the commission wishes to adjust a portion of the cost of service to follow a published price index, or to follow a utility-specific parameter — e.g., the actual seniority mix of employees, periodically adjusted for retirements and promotions — these changes in costs may be absorbed by the buffer.

The use of the revenue stability buffer to smooth out small cost fluctuations is incidental to its primary purpose of decoupling earnings from sales. Nonetheless, this use of the buffer has certain appealing aspects, compared to such alternatives as forecasting costs for rate cases, or introducing cost-of-service adjustment mechanisms similar to fuel clauses. First, the buffer system can better match the time of cost occurrence with the time of revenue collection, since the buffer is collected while the cost adjustment is being calculated and adjusted. Second, this approach eliminates the need to forecast costs, and can rely on real data. Third, since collection of the buffer fund is continuous (assuming sales do not fall dramatically), the advantages of regulatory lag (careful scrutiny of the issues) can be gained without the usual disadvantages (financial penalties for the petitioner). Data collection and hearings may take (say) six months, but the day after the adjustment is approved, the utility could transfer six months of increased revenues, with accrued interest, from the buffer fund to its own accounts (or vice versa, in the event of a cost decrease). Finally, the avoidance of cost-of-service adjustment surcharges, credits, refunds, and rate adjustments simplifies the customer's bill and increases the comprehensibility of the rate design and of the affect of consumption on the bill size.[9]

The Disadvantages of RSTR

The primary disadvantage of an RSTR system is that, like any other rate-making innovation, its implementation may conceal many other de facto changes in rate-making treatments. Particularly if the buffer is used to offset cost changes, it is possible that costs will be double-counted (included in base rates and again in an adjustment); that increases in some costs will be collected, without offsets for decreased costs of other types (or vice versa); or that standards of regulatory review or of due process will be compromised. The last possibility seems particularly likely for jurisdictions with limited regulatory staff support and limited public interest intervention. The small size of individual adjustments (compared to a full rate case), the competition of other matters for staff attention, and perhaps a perception of the RSTR buffer fund as "funny money," up for grabs, could result in only superficial review of the utility's proposed adjustments.

RSTR will certainly not eliminate all the difficulties currently faced by utilities or the regulatory system, but it should not create too many new ones. Any tendency in that direction can be controlled in several ways. First, all parties must come to view the buffer fund as the property of ratepayers, held in trust, until the commission finds otherwise. Frequent reports to the public on the size and disposition of the fund may be helpful in this regard. Second, the uses of the fund, whether for conservation, for tax relief, or for cost tracking, must be carefully specified and regulated.

The extent to which the commission must control the magnitude, distribution, and application of withdrawals for conservation or for tax relief will vary between jurisdictions and between utilities, but scrutiny of RSTR funds should not be substantially lower than regulatory scrutiny of other utility behavior. In general, rules for transfer of funds from the buffer to the utility's accounts, for cost-of-service adjustments, will have to be quite specific.

[9]The revenue adjustment mechanisms (RAM) recently approved for Pacific Gas and Electric Company and for Southern California Edison Company and requested by Niagara Mohawk Power Corporation face several of these problems, even though they promote revenue stability, not cost indexing. They are retrospective adjustments, suffering from regulatory lag; the revenue lost in a low-sales period may well be recovered by higher rates in a high-sales period. Customers' rates must vary as the adjustments are added to their base rates and fuel charges. The complexity and confusion resulting from RAM may have contributed to the California Public Utilities Commission's decision to apply RAM only when sales deviate more than 5 per cent from the forecast: the California RAM provides protection against massive revenue shortfalls, but not against small variations in sales.

prescribing the times at which costs will be reviewed, the types of costs which are to be included, and the method for calculating adjustments, to prevent any upward bias in the selection of costs, and to ensure that the mechanisms by which costs and offsets are measured in rate cases are not circumvented. Some commissions will find it easier and more efficient to regulate without RSTR (or with a limited version) than to construct an adequate system of RSTR review.

In addition to the general potential for abuse of RSTR, a half dozen assorted cautions are in order. First, it must be remembered that RSTR absolutely prevents the utility from receiving revenues in excess of those allocated, but only prevents revenue shortfalls by the size of the buffer: A utility which abruptly loses half its sales will still be in trouble.[10] Second, the actual size of the buffer (B^*) will vary randomly, so it cannot be counted on to fund any particular level of conservation, tax-relief, or cost-adjustment program. Third, very careful attention must be paid to the calculation of interest on the buffer, to prevent windfalls or penalties to the utility. Fourth, sales vary seasonally, and the revenue target may therefore vary between months, complicating the calculation of the actual size of the buffer. Fifth, jurisdictions which have implicitly relied on sales growth to help offset inflation must recognize that RSTR eliminates this limited source of rate relief. Sixth, it is important that any excess funds accumulated in the buffer not be used to reduce rate base. The buffer is to be established by and for current ratepayers, and should be applied to current expenses (utility or otherwise), not to rate base items which benefit customers for decades.

As the previous discussion indicates, there is certainly some potential for abuse of an RSTR system. Properly instituted, however, RSTR should have some major advantages — lower cost of capital, greater incentives for utility conservation — which should outweigh the burdens of operation of the system.

[10]This problem can be ameliorated by allowing the RSTR buffer to go negative, to be replenished in subsequent rate cases. Thus, the utility is assured of eventually receiving its allowed revenues, although its cash flow may still be problematic.