#74
#69

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF PUBLIC UTILITIES

Re: Boston Gas Company	D.P.U. 88-67

TESTIMONY OF PAUL L. CHERNICK

ON BEHALF OF THE

BOSTON HOUSING AUTHORITY

BOSTON HOUSING AUTHORITY
52 Chauncy Street
Boston, Massachusetts 02111

By: Michael B. Meyer, Esq.
Meyer, Connolly & Armstrong
10 Post Office Square
Boston, Massachusetts 02109

Dated: June 17, 1988

TABLE OF CONTENTS

TESTIMONY OF PAUL CHERNICK

on behalf of the

Boston Housing Authority

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 Department, 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 Department?

A: Yes. I have testified in about two dozen proceedings before the Department, on rate design, power plant performance standards, conservation potential and cost, QF rates, nuclear power plant costs, and other topics. Most recently, I filed testimony on behalf of the Conservation Law Foundation in Docket 86-36, on conservation program cost-recovery, and in the Petition of the Riverside Steam and Electric Company (May 18, 1988) on avoided-cost calculations.

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 three topics. First, Section 2 of this testimony will lay out the DPU's precedents for determining the cost-effectiveness of utility-sponsored conservation programs. I will also discuss why these precedents apply to the Boston Gas Company (BGC). Second, in Section 3, I will estimate the magnitude of BGC costs avoidable through efficiency improvements. Third, Section 4 will provide a cost-effectiveness analysis of BHA's proposed conservation program.

2. CONSERVATION PROGRAM EVALUATION

Q: Has Boston Gas Company (BGC) used versions of the "no-losers" test or the "lost base revenues" test in evaluating conservation and load management (C&LM)?

A: Yes. This can be seen in numerous BGC documents, including the following exhibits in this case:

1. Ex. BGC-62, pp. 1-1, 2-1 (the Meta Systems, Inc. 12/87 study),
2. Ex. BGC-60, pp. 1-5 (the BGC analysis of the Citizens Conservation Proposal),
3. Ex. BHA-2, p. 5 (the Tomlinson memo done for the Meta Systems, Inc. study),
4. Ex. BHA-3, p. 2 (the Flaherty 10/24/86 letter to Secretary Sharon Pollard of EOER), and
5. Ex. BHA-4 (I.R. BHA-43).

Q: Are these tests permitted by the Department?

A: No. These tests have been specifically rejected by the Department. See Re Boston Edison Company, D.P.U. 85-271-A/85-266-A, pp. 147-148 (6/26/86).

Q: Has BGC gone forward with C&LM programs which passed the Department's "marginal cost of conservation vs. marginal cost of supply" test?

A: No. For example, Ex. BGC-60 shows that BGC refused to go forward with a C&LM investment which cost $3/MMBTU/year for

3 years and which saved $6/MMBTU/year for 15 years. This program obviously passed the Department's test.

Q: Therefore, has BGC complied with numerous Department precedents dealing with C&LM, beginning with <u>Re Fitchburg Gas & Electric Company</u>, D.P.U. 84-145-A (1/31/85)?

A: No. The Department has clearly stated that appropriate cost-benefit tests compare the marginal cost of conservation to the marginal cost of the supply option. BGC has used only no-losers tests, which improperly count lost sales as a cost.

Q: Is the Department's precedent correct in this regard?

A: Yes. There is no reason to include lost revenues as a cost of conservation. This issue is addressed in two articles which I co-authored, and which are attached as Appendices C and D.

3. ESTIMATED AVOIDED COSTS DUE TO CONSERVATION

Q: How did you project Boston Gas Company's avoided costs due to conservation?

A: I started with Ex. BGC-33, Boston Gas Company's Marginal Cost Study. Table 3.2 is the basic input table for my analysis. Beginning in 1987 and ending in 2007, Table 3.2 identifies the incremental source of gas supply, the capacity cost of this supply, the commodity cost of the incremental source, and the commodity costs of other supplies that it offsets (for capacity purposes) or supplements (for commodity purposes).

Q: Conceptually, how does your study differ from the BGC marginal cost study?

A: The BGC marginal cost study (Ex. BGC-33) estimates 1987 marginal costs, in 1987 dollars. I have estimated avoided costs for each year from 1987 to 2007, in nominal dollars.

Q: How does your study differ from the Meta Systems study (Ex. BGC-62)?

A: There are four important differences. First, Meta Systems did not calculate the avoided cost due to conservation, but rather the average reduction in rates to non-participants due to conservation. Meta Systems thus incorrectly concluded that the benefits of conservation are less than average gas costs, when its own data indicate that the benefits are greater than average costs. Second, Meta Systems apparently chose to ignore 6.5 months of demand charges in every year, and thus reflected only 46% of the purchased gas capacity savings due to conservation. Third, Meta Systems assumed that there could be no demand-related conservation savings until 1995, even though BGC has not yet signed the contract for its projected 1991 supply, and has no assurance that NOREX (its current marginal cost) will ever be available. Fourth, Meta Systems examined only purchased gas costs, and ignored losses, savings in local production and distribution, and other factors recognized in BGC's marginal cost study.

Q: Have you corrected any portion of the Meta Systems study?

A: Yes. Appendix E corrects Meta System's calculation of the benefits of conservation (using only the purchased gas costs considered in the Meta Systems study). This correction simply eliminates the improper use of the no-losers test. The true benefits of conservation are roughly nine times as large as Meta Systems indicated, even without correcting any of Meta Systems' other errors.

Q: What are the incremental sources of supply in your study?

A: The incremental source of gas is NOREX in 1987-1990, PennEast in 1991, ANE in 1992-1994 and BGC's generic 'New' supply from 1995-2007.

Q: How did you determine what the incremental supply would be?

A: The incremental source of supply is determined largely by

Boston Gas Company's supply plans. In Ex. BGC-33, the Boston Gas Company uses NOREX to determine 1987 marginal costs. In addition to the NOREX supply of 39.6 MMBtu, Boston Gas is planning to add PennEast and ANE supplies of 29 and 17.5 MMBtu respectively. The "on" date for PennEast is November 11, 1990. ANE has an "on" date of November 11, 1991 (see Information Response BHA-89). The "New" supply is a typical new supply used by Boston Gas in the Meta Systems Study to estimate long term avoided costs due to conservation. I follow the Meta Systems Study in adding the "New" supply in 1995. BGC expects Champlain to come on line in the mid-90's, but does not have complete pricing information on the project. The source of the incremental supply is located in Table 3.2, line 1.

Q: How did you determine the capacity costs for the incremental supply sources?

A: Capacity costs for the NOREX supply are calculated from Ex. BGC-33 Schedule 1, workpapers p. 2. The annual demand charge of $4,571,000 is divided by the peak day capacity of 39.645 MMBtu to get the 1987 capacity cost of $115.30 per peak day MMBtu.

The capacity cost for PennEast and ANE are calculated similarly from data contained in Ex. BHA-11. The cost of "New" is from the Meta Systems Study. Capacity costs for the incremental supply sources are found in Table 3.2, line 2.a.

Q: How did you determine the marginal commodity costs?

A: The 1987 marginal commodity costs of the NOREX gas supply, of propane and of the mix of gas offset by the capacity addition are calculated from Ex. BGC-33 Schedule 1, workpapers p. 2. These figures, expressed as $/MMBtu, are found in Table 3.2, lines 3.a, 3.d, and 3.k, respectively. The marginal commodity costs of the PennEast and ANE supplies are calculated from Ex. BHA-11. The marginal commodity cost of the "New" is taken from the Meta Systems Study. The peak and off-peak marginal commodity costs for gas supplies other than the incremental supply (lines 3.e and 3.f in Table 3.2) are calculated from Ex. BGC-33 Schedule 4, workpapers p. 2.

Q: How is the marginal commodity cost divided between "gas" and "other" commodity charges?

A: In each case, a 1987 wellhead cost of gas of $1.61/MMBtu (from the Meta Systems study) is assumed. This is subtracted from the total marginal commodity cost to determine a corresponding value for the marginal commodity cost of "Other", the transmission and handling costs associated with that supply of gas.

Q: Why is this division necessary?

A: The cost is divided because the wellhead price of gas escalates at a different rate than the cost of transmission and handling does. The transmission and handling charges are increased at the GNP inflation rate of 4%, while the wellhead price of gas increases at the rates used in the Meta Systems Study to predict the future price of gas.

Q: How are "gas", "other" and the remaining inputs in Table 3.2 inflated over the time period in question?

A: All of the inputs except gas and propane are inflated at the projected annual GNP inflation rate of 4%. Gas and propane are inflated as indicated in the Meta Systems study: from 1987 to 1990 gas increases at 15.86%, from 1991 to 1995 it increases at 10.01%, at 10.34% 1996 to 2000 and at 4.83% from 2001 to 2007; propane escalates at 11.07% form 1987 to 1990, at 8.16% from 1991 to 1995, at 7.54% from 1996 to 2000 and at 4.83% after that. "Total gas" (for each type of gas) combines the inflation for wellhead gas and the 4% GNP inflation rate since it is the sum of "gas" and "other".

Demand charges are escalated at 4% except when the supply changes to a new source, as discussed above.

Q: Given these cost inputs, how did you derive net capacity costs in line 2.c of Table 3.1?

A: Net capacity costs are found by adjusting the capacity cost of the incremental source of supply by the commodity-related savings incurred when the use of more expensive supplies is reduced due to the availability of the incremental source. This information is calculated from Ex. BGC-33 Schedule 1, workpapers, p. 2. Dividing the change in total commodity costs of NOREX, other gas and propane due to the addition of the NOREX supply by NOREX's 39.645 MMBtu per peak day gives the capacity cost savings in dollars per peak day MMBtu. These values are then escalated at the appropriate rates.

Because BGC has not provided information comparable to that found in Ex. BGC-33 Schedule 1, workpapers p. 2, for the addition of the PennEast, ANE and New supplies,[1] I assume that the mix of gas saved when NOREX is added is the same as the mix saved by the addition of these later supplies. This assumption allows us to use the inflated commodity related savings calculated using NOREX as measure of the same savings associated with the addition of PennEast, ANE and New.

Q: How did you derive average marginal commodity costs?

A: The average marginal commodity costs for the peak and off-peak season are found in Table 3.1 lines 3.e and 3.f. This is a weighted average of the marginal commodity costs of the incremental supply, other gas and propane. For the peak season the incremental supply contributes 43.9% to the average cost, other gas contributes 44.75% and propane contributes 11.35%. In the off-peak season the incremental supply contributes 68.95% to the average marginal commodity cost and other gas makes up the remaining 31.05%. Since there is no propane usage in the off-peak season, it is not

---

1. Such information was requested in information request BHA-130.

included in this calculation. The weightings come from the proportional usage of NOREX, other gas and propane in the peak and off-peak seasons, as they are given in Ex. BGC-33, Schedule 4 workpapers p. 2.

Q: How did you derive seasonal capacity costs from the purchased gas costs in Table 3.3?

A: Table 3.3 summarizes marginal capacity costs. It is based substantially on Ex. BGC-33 Schedule 9. It differs from this schedule in two ways. First, for simplicity, Table 3.3 combines production and distribution costs, and presents only the peak period (since there are no off-peak capacity costs in BGC's model). The second change is more important. Table 3.3 includes a 19.5% reserve margin, line 8.a. Increasing the purchased gas capacity cost by this amount corrects for the omission of reserves in Boston Gas Company's marginal cost analysis. Since BGC has, and plans to maintain, substantial reserves, it is important to include the cost of those reserves in calculating marginal costs.[2]

---

2. I believe that there are other problems with BGC's marginal cost study, which tend to understate the marginal cost. For example, BGC has apparently omitted at least some of the costs of storage, such as interest charges, on the grounds that those costs are recovered in the CGA. Whether a marginal cost is recovered in the CGA or base rates does not determine whether or not it is marginal. By BGC's reasoning, no gas costs would be marginal, since they are all subject to collection through the CGA.

Similarly, BGC has failed to recognize an important cost of increased commodity sales: the loss of interruptible sales and margin. To the extent that firm sales reduce

Q: How is the reserve margin calculated?

A: This calculation is shown in Table 3.6. Boston Gas Company's projected design peak day send-out for the years 1987 to 1997 is divided into its projected peak day capacity over the same time period to determine how much more capacity the Company maintains above its expected design use. The average of these calculations is 19.5%, the factor by which purchased gas capacity costs are increased in Table 3.3.[3]

Q: How did you convert the Marginal supply cost in Table 3.1 to total Marginal commodity costs in Table 3.4?

A: The first two headings in Table 3.4, "On Peak Marginal Commodity Costs" and "Off-Peak Marginal Commodity Costs," repeat the calculations made in Ex. BGC-33 Schedule 10.

Q: How did you aggregate marginal commodity costs and marginal capacity costs in the last two headings in Table 3.4?

A: The total baseload non-heating or baseload marginal cost is found by taking a simple average of the on-peak marginal commodity cost and the off-peak marginal commodity cost and adding that number to the seasonal capacity cost divided by

---

interruptible sales, the cost of each MMBTU sold to a firm customer is the sum of the commodity cost and the interruptible margin.

I have not corrected either of these errors in my study, but BGC should be instructed to correct them in its next rate case.

3. BGC maintains additional planning reserves to compensate for load growth uncertainty (Ex. BGC-39, p. 5). I have not included this cost.

the 365 days over which baseload use is spread.

The calculation of the total marginal cost of the sensitive load is more complicated because this load is not constant over the year. I estimate weather sensitive marginal cost by taking the on-peak marginal commodity cost and adding it to the seasonal capacity cost divided by 69.32 days.

Q: Why did you use 69.32 days?

A: This figure is calculated in Table 3.5. It is found by taking annual normal year weather sensitive send-out in MMcf and dividing it by design year weather sensitive peak day send-out.

Q: How do your marginal cost estimates compare with BGC's?

A: BGC did not provide the information necessary to make such a comparison. BHA requested runs of the marginal cost study for future periods in information request BHA-130. When BGC belatedly provided a response to that request, it did not use its "best estimated prices" for NOREX, PennEast and ANE as given in Ex. BHA-11, nor did it any explanation for the prices used in this response. Since I do not know the basis for the response to BHA-130, I cannot correct BGC's analysis.

Q: How do your marginal cost estimates compare with the Meta Systems Study?

A: Over a fifteen year period beginning in 1991, I estimate weather sensitive marginal cost to be $17.90 and baseload marginal cost to be $8.43 (see Table 4.2). For the same time period the Meta Systems study, which examines only purchased gas costs, has a combined weather sensitive and baseload marginal cost of $13.29 (see Appendix E). The proximity of these figures indicates that my marginal cost estimates are, if anything, conservative.

4. EVALUATION OF BHA PROPOSED PROGRAMS

Q: How have determined the cost-effectiveness of the conservation programs proposed by the BHA?

A: In the previous section, I derived the levelized benefits of conservation programs starting in 1989-1991, and continuing for 5 to 20 years. The remaining task is to compute comparable costs of the conservation options proposed by the BHA through the testimony of Mr. Jackson. The first part of this task is to develop the levelized carrying charge of conservation per dollar of investment, as a function of the life of the conservation investment.

Q: How did you determine those carrying charges?

A: The derivation of the carrying charges for conservation is given in Appendix B. I have used the marginal cost of capital from Mr. Silvestrini's marginal cost study. I have assumed that BGC will expense the conservation expenditures for tax purposes in the year that the expenditures are made (year 0). To simplify the rate-making calculation, I have further assumed that the investments are all made at year-end, and the return is charged on the previous year-end rate base, with no projected costs or regulatory lag.

Since I assumed that the expenditure was expensed for tax purposes in year 0, the payments from ratepayers for depreciation are taxable. Thus, the tax column includes taxes on return (4.61% of the previous year-end rate base), and taxes on depreciation (1/(1-38.29%) - 1 = 62.05% of current-year depreciation).

A separate table in Appendix B lays out the calculation of the carrying charge for each useful life analyzed. At the bottom of the table, I take the present value of the annual charges to ratepayers (using BGC's marginal cost of capital), and the present value of $1 over the same number of years. The ratio of those two present values is the nominal levelized carrying charge (the equivalent of Mr. Silvestrini's "engineer's fixed charge rate," for the tax treatment of the conservation expenditures), the constant annual cost recovery necessary to provide the same present value as the actual cost recovery pattern for a $100 expenditure on conservation. The last column to the right of each table computes the real-levelized carrying charge, which is not used in this analysis, since Table 3.4 derives the benefits of conservation in nominal, rather than real, terms.

Q: How do these carrying charges relate to the cost of conservation per MMBTU saved?

A: The cost of conservation per MMBTU is:
cost * carrying charge / annual CCF saved * 10 CCF/MMBTU.
Table 4.1 computes the cost of conservation for each of the BHA's proposed measures. The costs, annual savings, and useful lives are from Mr. Jackson.

Q: How do these costs compare to the avoided supply costs calculated in Table 3.4?

A: Except for the domestic hot water tank insulation all of the measures reduce weather-sensitive load, which is much more expensive to serve. Table 4.2 compares the levelized cost per MMBTU of each conservation measure, from Table 4.1, with the levelized avoided supply cost for the same useful life, from Table 3.4. All of the measures are cost-effective for immediate implementation (e.g., year 0 = 1988 and savings start in 1989), except for DHW tank insulation at Infill, tightening windows at RAP/Rehab, and three measures at General Warren (new windows, new heat systems, and insulate slab). The new windows at General Warren will be cost-effective for 1989 implementation. If new heating systems are required at General Warren due to operating problems with the existing equipment, BGC could economically pay up to 84% of the replacement system cost, or about $70,000) to get the higher efficiency level in 1990.[4] Even higher payments would be justified for systems more efficient than those BHA has proposed.

Table 4.3 lists the costs and annual savings from the cost-effective measures identified in Table 4.2. A total of $2,025,062 of investments are cost-effective, which would save 1,174,993 CCF annually, at an average cost of

---

4. This calculation assumes that the conventional replacements would be no more efficient than the existing units.

$3.31/MMBTU.

Q: What is your conclusion from this analysis?

A: BGC should be ordered to implement the conservation efficiency improvements identified as cost-effective in Table 4.2. BGC should be further ordered to identify and to achieve similar savings for its other customers, especially those with limited access to capital.

Q: Does this conclude your testimony?

A: Yes.

TABLES

	1987	1988	1989	1990	1991	1992	1993	1994
1. Incremental Source	NOREX	NOREX	NOREX	NOREX	PENNEAST	ANE	ANE	ANE
2. Capacity Cost								
a. Demand Cost	115.30	119.91	124.71	129.70	240.72	478.28	497.42	517.31
b. Commodity Savings								
Incremental	-125.06	-140.66	-158.57	-179.15	-158.59	-189.74	-207.48	-226.95
Other Gas	93.88	108.77	126.02	146.01	160.65	176.76	194.49	214.00
Propane	62.81	69.76	77.49	86.06	93.09	100.68	108.90	117.78
Net Commodity Savings	31.63	37.87	44.93	52.92	95.15	87.71	95.91	104.84
c. Net Capacity Cost	83.67	82.04	79.78	76.77	145.57	390.58	401.50	412.47
3. Commodity Cost ($/MMBtu)								
a. incremental supply	2.25	2.53	2.86	3.23	2.86	3.42	3.74	4.09
b. other gas peak	2.34	2.63	2.95	3.33	3.61	3.92	4.26	4.64
c. propane	4.16	4.62	5.13	5.70	6.17	6.67	7.21	7.80
d. other gas off-peak	2.74	3.05	3.39	3.78	4.08	4.41	4.77	5.16
e. weighted peak	2.51	2.81	3.16	3.55	3.57	4.01	4.37	4.75
f. weighted off-peak	2.10	2.37	2.69	3.05	2.48	3.11	3.42	3.75

NOTES:

[1] Incremental Source: 1987-1990 NOREX, 1991 PENNEAST, 1992-94 ANE, 1995-2007 'NEW' a typical new source.

[2.a] Demand Charge: From Table 3.2, Row [2.a].

[2.b] Commodity Savings: calculated from Ex.BGC-33 Schedule 1 workpapers p. 2, escalated at the appropriate rate.

[2.c] Net Capacity Cost: [2.a]-Net Commodity Savings.

[3.a] incremental supply: From Table 3.2, Row [3.a].

[3.b] other gas peak: From Table 3.2, Row [3.e].

[3.c] propane: From Table 3.2, Row [3.d].

[3.d] other gas off-peak: From Table 3.2, Row [3.h].

[3.e] weighted peak: 43.9%*[3.a] + 44.75%*[3.b] + 11.35%*[3.c].

[3.f] weighted off-peak: (1+31.05%)*[3.a] - 31.05%[3.d].

	1995	1996	1997	1998	1999	2000	2001
1. Incremental Source	NEW	NEW	NEW	NEW	NEW	NEW	NEW
2. Capacity Cost							
a. Demand Cost	625.57	650.60	676.62	703.68	731.83	761.11	791.55
b. Commodity Savings							
Incremental	-315.09	-341.90	-371.27	-403.42	-438.65	-477.27	-499.40
Other Gas	235.47	259.81	286.68	316.32	349.03	385.12	403.72
Propane	127.40	137.00	147.33	158.44	170.39	183.23	192.08
Net Commodity Savings	47.77	54.91	62.74	71.34	80.76	91.08	96.40
c. Net Capacity Cost	577.80	595.69	613.88	632.35	651.07	670.02	695.15
3. Commodity Cost ($/MMBtu)							
a. incremental supply	5.68	6.16	6.69	7.27	7.90	8.60	8.99
b. other gas peak	5.04	5.50	6.00	6.55	7.16	7.83	8.19
c. propane	8.44	9.07	9.76	10.49	11.29	12.14	12.72
d. other gas off-peak	5.59	6.07	6.60	7.17	7.80	8.49	8.89
e. weighted peak	5.71	6.19	6.73	7.31	7.95	8.65	9.06
f. weighted off-peak	5.70	6.19	6.72	7.30	7.93	8.63	9.03

	2002	2003	2004	2005	2006	2007
1. Incremental Source	NEW	NEW	NEW	NEW	NEW	NEW
2. Capacity Cost						
a. Demand Cost	823.21	856.14	890.39	926.00	963.04	1001.56
b. Commodity Savings						
Incremental	-522.57	-546.82	-572.20	-598.76	-626.56	-655.67
Other Gas	423.22	443.66	465.09	487.55	511.10	535.79
Propane	201.36	211.09	221.28	231.97	243.17	254.92
Net Commodity Savings	102.01	107.93	114.17	120.76	127.71	135.04
c. Net Capacity Cost	721.20	748.21	776.21	805.24	835.33	866.52
3. Commodity Cost ($/MMBtu)						
a. incremental supply	9.41	9.85	10.31	10.78	11.29	11.81
b. other gas peak	8.58	8.98	9.40	9.85	10.31	10.80
c. propane	13.34	13.98	14.66	15.37	16.11	16.89
d. other gas off-peak	9.30	9.73	10.19	10.66	11.16	11.68
e. weighted peak	9.48	9.93	10.40	10.88	11.40	11.93
f. weighted off-peak	9.45	9.88	10.34	10.82	11.33	11.85

TABLE 3.2

		1987	1988	1989	1990	1991	1992	1993	1994
1. Incremental Source		NOREX	NOREX	NOREX	NOREX	PENNEAST	ANE	ANE	ANE
2. Capacity Costs									
a. Incremental Supply ($/peak day MMBtu)		115.30	119.91	124.71	129.70	240.72	478.28	497.42	517.31
3. Commodity Costs ($/MMBtu)									
Incremental Commodity	a. Total:	2.25	2.53	2.86	3.23	2.86	3.42	3.74	4.09
	b. Gas:	1.61	1.87	2.16	2.50	2.76	3.03	3.34	3.67
	c. Other:	0.64	0.67	0.69	0.72	0.10	0.39	0.40	0.42
	d. Propane:	4.16	4.62	5.13	5.70	6.17	6.67	7.21	7.80
Other Gas Peak Commodity	e. Total:	2.34	2.63	2.95	3.33	3.61	3.92	4.26	4.64
	f. Gas:	1.61	1.87	2.16	2.50	2.76	3.03		
	g. Other:	0.73	0.76	0.79	0.82	0.86	0.89		
Other Gas Off-Peak Commodity	h. Total:	2.74	3.05	3.39	3.78	4.08	4.41		
	i. Gas:	1.61	1.87	2.16	2.50	2.76	3.03		
	j. Other:	1.13	1.18	1.23	1.28	1.33	1.38		
Other Gas Mix used in Capacity Cost Offset	k. Total:	2.32	2.61	2.93	3.31	3.59	3.90		
	l. Gas:	1.61	1.87	2.16	2.50	2.76	3.03		
	m. Other:	0.71	0.74	0.77	0.80	0.83	0.87		

NOTE 3b
PennEast and ANE from EX BHA-11

NOTES:

[2.a] Norex: $115.5/peakday MMBtu=$4,571,000/39,600 MMBtu;
PennEast: $214/peakday MMBtu=$6,206,000/29,000 MMBtu;
ANE: $408.84/peakday MMBtu=$7,154,700/17,500 MMBtu;
New: $476.2/peakday MMBtu=$5 million/10,500 MMBtu;
escalated at 4% 1987-2007.

[3.a] Total: [3b] + [3c].

[3.b] Gas: escalated at 15.86% 1987-90, at 10.03% 1991-95, at 10.34% 1996-2000 and at 4.83% 2001-2007; see Metasystems study. Norex: calculated from Ex.BGC-33 Schedule 1, workpapers p. 2; PennEast and ANE from discovery response xx; NEW see Metasystems study p. 4-5.

[3.c] Other: escalated at 4% 1987-2007; calculated from Ex-BGC-33 Schedule 1, workpapers p. 2.

[3.d] Propane: escalated at 11.07% 1987-90, at 8.16% 1991-1995, at 7.54% 1996-2000, at 4.83% 2001-2007; escalation from Metasystem study; calculated from Ex. BGC-33 Schedule 1, workpapers p.2.

[3.e] Calculated from Ex.BGC-33 Schedule 4, workpapers p. 2.

[3.h] Calculated from Ex.BGC-33 Schedule 4, workpapers p. 2.

[3.k] Total: [3.l] + [3.m]; calculated from Ex. BGC-33 Schedule 1, workpapers p. 2.

TABLE 3.2

		1995	1996	1997	1998	1999	2000	2001
1. Incremental Source		NEW	NEW	NEW	NEW	NEW	NEW	NEW
2. Capacity Costs								
a. Incremental Supply ($/peak day MMBtu)		625.57	650.60	676.62	703.68	731.83	761.11	791.55
3. Commodity Costs ($/MMBtu)								
Incremental Commodity	a. Total:	5.68	6.16	6.69	7.27	7.90	8.60	8.99
	b. Gas:	4.04	4.46	4.92	5.42	5.99	6.60	6.92
	c. Other:	1.64	1.70	1.77	1.84	1.92	1.99	2.07
	d. Propane:	8.44	9.07	9.76	10.49	11.29	12.14	12.72
Other Gas Peak Commodity	e. Total:	5.04	5.50	6.00	6.55	7.16	7.83	8.19
	f. Gas:	4.04	4.46	4.92	5.42	5.99	6.60	6.92
	g. Other:	1.00	1.04	1.09	1.13	1.17	1.22	1.27
Other Gas Off-Peak Commodity	h. Total:	5.59	6.07	6.60	7.17	7.80	8.49	8.89
	i. Gas:	4.04	4.46	4.92	5.42	5.99	6.60	6.92
	j. Other:	1.55	1.62	1.68	1.75	1.82	1.89	1.97
Other Gas Mix used in Capacity Cost Offset	k. Total:	5.01	5.47	5.97	6.52	7.13	7.79	8.16
	l. Gas:	4.04	4.46	4.92	5.42	5.99	6.60	6.92
	m. Other:	0.98	1.01	1.05	1.10	1.14	1.19	1.23

TABLE 3.2

		2002	2003	2004	2005	2006	2007
1. Incremental Source		NEW	NEW	NEW	NEW	NEW	NEW
2. Capacity Costs							
a. Incremental Supply ($/peak day MMBtu)		823.21	856.14	890.39	926.00	963.04	1001.56
3. Commodity Costs ($/MMBtu)							
Incremental Commodity	a. Total:	9.41	9.85	10.31	10.78	11.29	11.81
	b. Gas:	7.26	7.61	7.98	8.36	8.77	9.19
	c. Other:	2.15	2.24	2.33	2.42	2.52	2.62
	d. Propane:	13.34	13.98	14.66	15.37	16.11	16.89
Other Gas Peak Commodity	e. Total:	8.58	8.98	9.40	9.85	10.31	10.80
	f. Gas:	7.26	7.61	7.98	8.36	8.77	9.19
	g. Other:	1.32	1.37	1.43	1.49	1.55	1.61
Other Gas Off-Peak Commodity	h. Total:	9.30	9.73	10.19	10.66	11.16	11.68
	i. Gas:	7.26	7.61	7.98	8.36	8.77	9.19
	j. Other:	2.04	2.13	2.21	2.30	2.39	2.49
Other Gas Mix used in Capacity Cost Offset	k. Total:	8.54	8.94	9.36	9.80	10.27	10.75
	l. Gas:	7.26	7.61	7.98	8.36	8.77	9.19
	m. Other:	1.28	1.33	1.39	1.44	1.50	1.56

TABLE 3.3: SUMMARY OF MARGINAL CAPACITY COSTS

	1987	1988	1989	1990	1991	1992	1993	1994
PLANT INVESTMENT								
1. LR Unit Costs, $/Peak Day MMBtu	$379.19	$394.36	$410.13	$426.54	$443.60	$461.34	$479.80	$498.99
2. General Plant Loading Factor	3.14%	3.14%	3.14%	3.14%	3.14%	3.14%	3.14%	3.14%
3. Unit Costs + Loading Factor	$391.10	$406.74	$423.01	$439.93	$457.53	$475.83	$494.86	$514.66
4. Fixed Rate Charge	12.37%	12.37%	12.37%	12.37%	12.37%	12.37%	12.37%	12.37%
5. A & G Exp Plant-Related Loading Factor	1.07%	1.07%	1.07%	1.07%	1.07%	1.07%	1.07%	1.07%
6. Total Rate ([4]+[5])	13.44%	13.44%	13.44%	13.44%	13.44%	13.44%	13.44%	13.44%
7. Annualized Cost ([3]*[6])	$52.56	$54.67	$56.85	$59.13	$61.49	$63.95	$66.51	$69.17
OPERATING EXPENSES								
8. Purchased Gas Capacity Cost	$83.67	$82.04	$79.78	$76.77	$145.57	$390.58	$401.50	$412.47
8.a. With Reserves	$99.99	$98.04	$95.33	$91.74	$173.95	$466.74	$479.80	$492.90
9. Production Capacity Cost	$6.99	$7.27	$7.56	$7.86	$8.18	$8.50	$8.84	$9.20
10. Distribution Capacity Cost	$25.25	$26.26	$27.31	$28.40	$29.54	$30.72	$31.95	$33.23
11. A&G Exp Non-Plant Loading Factor	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%
12. Loading ([9]+[10])*(1+[11])	$45.00	$46.80	$48.67	$50.62	$52.64	$54.75	$56.94	$59.22
13. Total Capacity Expenses ([8a]+[12])	$144.99	$144.84	$144.00	$142.36	$226.60	$521.49	$536.74	$552.12
14. Total Working Capital	$18.73	$19.08	$19.40	$19.69	$25.70	$45.73	$47.18	$48.67
15. Working Capital Rev. Req'd ([14]*16.93%)	$3.17	$3.23	$3.28	$3.33	$4.35	$7.74	$7.99	$8.24
16. System Seasonal Capacity Related Cost $/Design Day MMBtu ([7]+[13]+[15])	$200.72	$202.74	$204.14	$204.82	$292.44	$593.19	$611.23	$629.53
17. Loss Factor	95.70%	95.70%	95.70%	95.70%	95.70%	95.70%	95.70%	95.70%
18. Seasonal Capacity Cost ([16]/[17])	$209.74	$211.85	$213.31	$214.03	$305.58	$619.84	$638.70	$657.82

NOTES

[1] Long Run Unit Cost: Inflated at 4%.

[8] Purchased Gas Capacity Cost: Table 3.1, Row [2.c].

[8a] Purchased Gas Capacity Costs increased by 19.5% reserve ratio, see Table 3.6.

[9] Production Capacity Cost: Inflated at 4%.

[10] Distribution Capacity Cost: Inflated at 4%.

[14] Total Working Capital: M&S costs + Work Cash O&M; M&S costs = [3]*Material and Supplies and Prepayments loader from Ex. BGC-33 Schedule 7; Work Cash computed on the basis of 29 days net lag for gas and 45 days for other =([12]*45+[8]*29/365.

[15] Working Capital Rev. Req'd computation: (Working Capital)* Weighted Cost of Capital)/1-Combined tax rate 16.93%.

TABLE 3.3: SUMMARY OF MARGINAL CAPACITY COSTS

	1995	1996	1997	1998	1999	2000	2001
PLANT INVESTMENT							
1. LR Unit Costs, $/Peak Day MMBtu	$518.95	$539.71	$561.29	$583.75	$607.10	$631.38	$656.63
2. General Plant Loading Factor	3.14%	3.14%	3.14%	3.14%	3.14%	3.14%	3.14%
3. Unit Costs + Loading Factor	$535.24	$556.65	$578.92	$602.08	$626.16	$651.20	$677.25
4. Fixed Rate Charge	12.37%	12.37%	12.37%	12.37%	12.37%	12.37%	12.37%
5. A & G Exp Plant-Related Loading Factor	1.07%	1.07%	1.07%	1.07%	1.07%	1.07%	1.07%
6. Total Rate ([4]+[5])	13.44%	13.44%	13.44%	13.44%	13.44%	13.44%	13.44%
7. Annualized Cost ([3]*[6])	$71.94	$74.81	$77.81	$80.92	$84.16	$87.52	$91.02
OPERATING EXPENSES							
8. Purchased Gas Capacity Cost	$577.80	$595.69	$613.88	$632.35	$651.07	$670.02	$695.15
8.a. With Reserves	$690.47	$711.85	$733.58	$755.65	$778.03	$800.68	$830.71
9. Production Capacity Cost	$9.57	$9.95	$10.35	$10.76	$11.19	$11.64	$12.10
10. Distribution Capacity Cost	$34.56	$35.94	$37.38	$38.87	$40.43	$42.04	$43.72
11. A&G Exp Non-Plant Loading Factor	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%
12. Loading ([9]+[10])*(1+[11])	$61.59	$64.05	$66.61	$69.28	$72.05	$74.93	$77.93
13. Total Capacity Expenses ([8a]+[12])	$752.06	$775.90	$800.19	$824.93	$850.08	$875.61	$908.63
14. Total Working Capital	$62.44	$64.52	$66.65	$68.84	$71.07	$73.35	$76.15
15. Working Capital Rev. Req'd ([14]*16.93%)	$10.57	$10.92	$11.28	$11.65	$12.03	$12.42	$12.89
16. System Seasonal Capacity Related Cost $/Design Day MMBtu ([7]+[13]+[15])	$834.56	$861.63	$889.28	$917.50	$946.26	$975.55	$1,012.55
17. Loss Factor	95.70%	95.70%	95.70%	95.70%	95.70%	95.70%	95.70%
18. Seasonal Capacity Cost ([16]/[17])	$872.06	$900.35	$929.24	$958.73	$988.78	$1,019.38	$1,058.04

TABLE 3.3: SUMMARY OF MARGINAL CAPACITY COSTS

	2002	2003	2004	2005	2006	2007
PLANT INVESTMENT						
1. LR Unit Costs, $/Peak Day MMBtu	$682.90	$710.22	$738.62	$768.17	$798.90	$830.85
2. General Plant Loading Factor	3.14%	3.14%	3.14%	3.14%	3.14%	3.14%
3. Unit Costs + Loading Factor	$704.34	$732.52	$761.82	$792.29	$823.98	$856.94
4. Fixed Rate Charge	12.37%	12.37%	12.37%	12.37%	12.37%	12.37%
5. A & G Exp Plant-Related Loading Factor	1.07%	1.07%	1.07%	1.07%	1.07%	1.07%
6. Total Rate ([4]+[5])	13.44%	13.44%	13.44%	13.44%	13.44%	13.44%
7. Annualized Cost ([3]*[6])	$94.66	$98.45	$102.39	$106.48	$110.74	$115.17
OPERATING EXPENSES						
8. Purchased Gas Capacity Cost	$721.20	$748.21	$776.21	$805.24	$835.33	$866.52
8.a. With Reserves	$861.84	$894.11	$927.57	$962.26	$998.22	$1,035.49
9. Production Capacity Cost	$12.59	$13.09	$13.62	$14.16	$14.73	$15.32
10. Distribution Capacity Cost	$45.47	$47.29	$49.18	$51.15	$53.20	$55.33
11. A&G Exp Non-Plant Loading Factor	39.58%	39.58%	39.58%	39.58%	39.58%	39.58%
12. Loading ([9]+[10])*(1+[11])	$81.04	$84.29	$87.66	$91.16	$94.81	$98.60
13. Total Capacity Expenses ([8a]+[12])	$942.88	$978.40	$1,015.23	$1,053.42	$1,093.03	$1,134.09
14. Total Working Capital	$79.06	$82.07	$85.20	$88.45	$91.82	$95.31
15. Working Capital Rev. Req'd ([14]*16.93%)	$13.38	$13.89	$14.42	$14.97	$15.54	$16.14
16. System Seasonal Capacity Related Cost $/Design Day MMBtu ([7]+[13]+[15])	$1,050.93	$1,090.74	$1,132.04	$1,174.88	$1,219.32	$1,265.40
17. Loss Factor	95.70%	95.70%	95.70%	95.70%	95.70%	95.70%
18. Seasonal Capacity Cost ([16]/[17])	$1,098.15	$1,139.75	$1,182.91	$1,227.67	$1,274.10	$1,322.26

TABLE 3.4: SUMMARY OF MARGINAL COMMODITY COSTS AND TOTAL MARGINAL COSTS

		1987	1988	1989	1990	1991	1992	1993	1994
ON PEAK MARGINAL COMMODITY COSTS									
1. Unit Cost of Incremental Supply		$2.510	$2.813	$3.158	$3.553	$3.571	$4.013	$4.367	$4.754
2. Total Variable Commodity Cost		$2.512	$2.815	$3.161	$3.556	$3.574	$4.016	$4.371	$4.758
3. Working Capital Rev Req		$0.034	$0.038	$0.043	$0.048	$0.048	$0.054	$0.059	$0.064
4. System Seasonal Commodity Related Cost		$2.546	$2.853	$3.204	$3.604	$3.622	$4.071	$4.430	$4.822
5. Marginal Commodity Cost		$2.660	$2.981	$3.348	$3.766	$3.784	$4.253	$4.629	$5.039
OFF-PEAK MARGINAL COMMODITY COSTS									
1. Unit Cost of Incremental Supply		$2.100	$2.375	$2.691	$3.055	$2.476	$3.109	$3.416	$3.754
2. Total Variable Commodity Cost		$2.101	$2.377	$2.693	$3.057	$2.478	$3.111	$3.419	$3.757
3. Working Capital Rev Req		$0.028	$0.032	$0.036	$0.041	$0.033	$0.042	$0.046	$0.051
4. System Seasonal Commodity Related Cost		$2.130	$2.409	$2.729	$3.098	$2.511	$3.153	$3.465	$3.807
5. Marginal Commodity Cost		$2.225	$2.517	$2.852	$3.238	$2.624	$3.295	$3.620	$3.978
BASELOAD MARGINAL COST [6]		$3.02	$3.33	$3.68	$4.09	$4.04	$5.47	$5.87	$6.31
Levelized Costs	over 5 years			$4.50	$5.01	$5.81			
	over 7 years			$5.09	$5.78	$6.54			
	over 10 years			$5.95	$6.65	$7.40			
	over 15 years			$7.01	$7.70	$8.43			
	over 20 years			$7.73	$8.43	$9.17			
WEATHER SENSITIVE MARGINAL COST [7]		$5.69	$6.04	$6.42	$6.85	$8.19	$13.20	$13.84	$14.53
Levelized Costs	over 5 years			$9.22	$10.83	$13.16			
	over 7 years			$10.73	$12.55	$14.59			
	over 10 years			$12.58	$14.25	$16.12			
	over 15 years			$14.59	$16.17	$17.90			
	over 20 years			$15.94	$17.49	$19.21			

NOTES

[1] Unit Cost of Incremental Supply: From Table 3.1, Line 3.e Peak, Line 3.f Off-Peak.

[2] Total Variable Commodity Cost: ([1]*.06%*1.3958)+[1]

[3] Working Capital Rev Req: Total Working Capital*16.93%

[4] System Seasonal Commodity Related Cost: [2]+[3]

[5] Marginal Commodity Cost: [4]/Loss Factor; Loss Factor = .957.

[6] Baseload Marginal Cost: (On-peak Marginal Commodity cost + Off-peak Marginal Commodity cost)/2 + Seasonal Capacity Cost/365. See Table 3.3 line 18.

[7] Weather Sensitive Marginal Cost: On-Peak Marginal Commodity Cost + Seasonal Capacity Cost/69.32. See Table 3.3 line 18. For the derivation of 69.32 see Table 3.5.

TABLE 3.4: SUMMARY OF MARGINAL COMMODITY COSTS AND TOTAL MARGINAL COSTS

		1995	1996	1997	1998	1999	2000	2001
ON PEAK MARGINAL COMMODITY COSTS								
1. Unit Cost of Incremental Supply		$5.705	$6.194	$6.729	$7.314	$7.953	$8.653	$9.060
2. Total Variable Commodity Cost		$5.710	$6.200	$6.735	$7.320	$7.960	$8.661	$9.067
3. Working Capital Rev Req		$0.077	$0.083	$0.091	$0.099	$0.107	$0.117	$0.122
4. System Seasonal Commodity Related Cost		$5.787	$6.283	$6.825	$7.418	$8.067	$8.777	$9.189
5. Marginal Commodity Cost		$6.047	$6.565	$7.132	$7.752	$8.430	$9.172	$9.602
OFF-PEAK MARGINAL COMMODITY COSTS								
1. Unit Cost of Incremental Supply		$5.701	$6.185	$6.715	$7.295	$7.931	$8.628	$9.028
2. Total Variable Commodity Cost		$5.706	$6.190	$6.721	$7.302	$7.938	$8.635	$9.035
3. Working Capital Rev Req		$0.077	$0.083	$0.090	$0.098	$0.107	$0.116	$0.122
4. System Seasonal Commodity Related Cost		$5.783	$6.274	$6.811	$7.400	$8.045	$8.751	$9.157
5. Marginal Commodity Cost		$6.043	$6.556	$7.117	$7.732	$8.406	$9.145	$9.569
BASELOAD MARGINAL COST [6]		$8.43	$9.03	$9.67	$10.37	$11.13	$11.95	$12.48
Levelized Costs	over 5 years							
	over 7 years							
	over 10 years							
	over 15 years							
	over 20 years							
WEATHER SENSITIVE MARGINAL COST [7]		$18.63	$19.55	$20.54	$21.58	$22.69	$23.88	$24.87
Levelized Costs	over 5 years							
	over 7 years							
	over 10 years							
	over 15 years							
	over 20 years							

TABLE 3.4: SUMMARY OF MARGINAL COMMODITY COSTS AND TOTAL MARGINAL COSTS

		2002	2003	2004	2005	2006	2007
ON PEAK MARGINAL COMMODITY COSTS							
1. Unit Cost of Incremental Supply		$9.485	$9.930	$10.397	$10.885	$11.396	$11.932
2. Total Variable Commodity Cost		$9.493	$9.939	$10.405	$10.894	$11.406	$11.942
3. Working Capital Rev Req		$0.128	$0.134	$0.140	$0.147	$0.153	$0.161
4. System Seasonal Commodity Related Cost		$9.621	$10.072	$10.545	$11.041	$11.559	$12.103
5. Marginal Commodity Cost		$10.053	$10.525	$11.019	$11.537	$12.079	$12.646
OFF-PEAK MARGINAL COMMODITY COSTS							
1. Unit Cost of Incremental Supply		$9.446	$9.885	$10.343	$10.823	$11.325	$11.851
2. Total Variable Commodity Cost		$9.454	$9.893	$10.352	$10.832	$11.335	$11.861
3. Working Capital Rev Req		$0.127	$0.133	$0.139	$0.146	$0.153	$0.160
4. System Seasonal Commodity Related Cost		$9.582	$10.026	$10.491	$10.978	$11.487	$12.021
5. Marginal Commodity Cost		$10.012	$10.477	$10.962	$11.471	$12.004	$12.561
BASELOAD MARGINAL COST [6]		$13.04	$13.62	$14.23	$14.87	$15.53	$16.23
Levelized Costs	over 5 years						
	over 7 years						
	over 10 years						
	over 15 years						
	over 20 years						
WEATHER SENSITIVE MARGINAL COST [7]		$25.89	$26.97	$28.08	$29.25	$30.46	$31.72
Levelized Costs	over 5 years						
	over 7 years						
	over 10 years						
	over 15 years						
	over 20 years						

TABLE 3.5: DERIVATION OF ANNUAL HEAT SENSITIVE MMcf/PEAK DAY MMcf

1.	Normal Year Sendout	67823.78
2.	Normal Year Daily Baseload Sendout	66.92
3.	Normal Year Heat Sensitive Sendout	43397.98
4.	Design Year Peak Day Sendout	692.98
5.	Design Year Peak Day Heat Sensitive Sendout	626.06
6.	Annual Heat Sensitive MMcf/Peak Day MMcf	69.32

Notes:

[1]: From EX. BGC-43.

[2]: From Ex. BGC-42

[3]: [1]-365*[2].

[4]: From Ex. BGC-44.

[5]: [4] - [2].

[6]: [3]/[5].

TABLE 3.6: RESERVE CAPACITY CALCULATION

	1987-88	1988-89	1989-90	1990-91	1991-92	1992-93	1993-94	1994-95	1995-96	1996-97	1997-98
Design Peak Day Send Out [1]	692.98	728.5	743.1	748.1	758.2	763.2	772.1	781.2	790.3	799.6	808.9
% change		4.88%	1.96%	0.67%	1.33%	0.66%	1.16%	1.16%	1.16%	1.16%	1.16%
average change 1987-1992:	1.17%										
Capacity [2]	876.2	876.2	916.2	945.2	962.7	962.7	962.7	980.2	980.2	980.2	980.2
New Capacity by given in-service dates, or EFSC forecast loads											
Norex			40								
PennEast				29							
ANE					17.5						
Champlain								17.5			
Reserves	20.91%	16.86%	18.89%	20.85%	21.24%	20.72%	19.80%	20.31%	19.37%	18.43%	17.48%
Cumulative Average	20.91%	18.88%	18.89%	19.38%	19.75%	19.91%	19.90%	19.95%	19.88%	19.74%	19.53%

NOTES:

[1]: 1987-88 From BGC Discovery Response COB-156, 1988-99 - 1992-93 From BGC Information Response BHA-80, 1993-94 on, escalated at average change 1987-1992.

Table 4.1 : BOSTON HOUSING AUTHORITY CONSERVATION MEASURES

DEVELOPMENT	MEASURE	COST [1]	ANNUAL CCF [2]	LIFE (yrs) [3]	LEVELIZED CARRYING CHARGE [4]	ANNUAL COST [5]	ANNUAL COST OF SAVINGS ($/MMBTU) [6]
General Warren	DHW Tank Insulation	$2,500	946	15	13.68%	$342.00	$3.61
	Door Weatherstripping	$8,951	3378	7	20.94%	$1,874.34	$5.55
	Clock Thermostats	$3,192	1229	15	13.68%	$436.67	$3.55
	Flue Damper	$3,528	940	10	16.72%	$589.88	$6.27
	Tighten Windows	$301	87	7	20.94%	$63.03	$7.26
	Intermittent Ignition	$26,784	5626	10	16.72%	$4,478.28	$7.96
	Attic Insulation	$15,573	3716	15	13.68%	$2,130.39	$5.73
	WS Windows	$446	88	7	20.94%	$93.39	$10.59
	New Windows	$29,447	2083	20	12.34%	$3,633.76	$17.45
	New Heat Systems	$82,848	4498	20	12.34%	$10,223.44	$22.73
	Insulate Slab	$77,580	2336	15	13.68%	$10,612.94	$45.44
	Insulate Ducts	$5,858	2097	15	13.68%	$801.37	$3.82
RAP/Rehab	DHW Tank Insulation	$1,083	526	15	13.68%	$148.15	$2.82
	Door Weatherstripping	$1,102	445	7	20.94%	$230.76	$5.18
	Clock Thermostats	$2,736	1933	15	13.68%	$374.28	$1.94
	Tighten Windows	$4,510	188	7	20.94%	$944.39	$50.17
Gallivan Boulevard	Boiler Reset	$91,390	19805	10	16.72%	$15,280.41	$7.72
	Intermittent Ignition	$68,913	14760	10	16.72%	$11,522.25	$7.81
	Flue Damper	$16,954	9538	10	16.72%	$2,834.71	$2.97
	Wall Insulation	$262,237	68804	15	13.68%	$35,874.02	$5.21
	Attic Insulation	$70,078	7932	15	13.68%	$9,586.67	$12.09
Infill Properties	DHW Tank Insulation	$2,338	350	15	13.68%	$319.84	$9.13
	Clock Thermostat	$5,718	8136	15	13.68%	$782.22	$0.96
	Flue Damper	$4,698	4700	10	16.72%	$785.51	$1.67
	Intermittent Ignition	$14,141	3060	10	16.72%	$2,364.38	$7.73
	Boiler Reset	$18,232	10062	10	16.72%	$3,048.39	$3.03
Various	Energy Management System	$575,000	239583	15	13.68%	$78,660.00	$3.28
Old Colony & Charlestown	Steam Traps	$796,200	765517	5	26.75%	$212,983.50	$2.78

Notes:
[1],[2],[3]: From D. Jackson, BHA
[4]: Appendix B
[5]: [4]*[1]
[6]: [5]/[2]*10, for 10 CCF per MMBTU

Table 4.2 : COMPARISON OF COSTS AND BENEFITS OF BOSTON HOUSING AUTHORITY CONSERVATION MEASURES

DEVELOPMENT	MEASURE	ANNUAL COST OF SAVINGS ($/MMBTU) [1]	LIFE (yrs) [2]	Type of Use [3]	Levelized Avoided Cost Starting [4] 1989	1990	1991
General Warren	DHW Tank Insulation	$3.61	15	WH = H_2O HEATING			
	Door Weatherstripping	$5.55	7	INS = INSULATION			
	Clock Thermostats	$3.55	15	HS = HEATING SEASON, PROP.			
	Flue Damper	$6.27	10	HS			
	Tighten Windows	$7.26	7	INS			
	Intermittent Ignition	$7.96	10	HS			
	Attic Insulation	$5.73	15	INS			
	WS Windows	$10.59	7	INS			
	New Windows	$17.45	20	INS			
	New Heat Systems	$22.73	20	HS			
	Insulate Slab	$45.44	15	INS			
	Insulate Ducts	$3.82	15	INS			
RAP/Rehab	DHW Tank Insulation	$2.82	15	WH			
	Door Weatherstripping	$5.18	7	INS			
	Clock Thermostats	$1.94	15	HS			
	Tighten Windows	$50.17	7	INS			
Gallivan Boulevard	Boiler Reset	$7.72	10	~~HS~~ Ins			
	Intermittent Ignition	$7.81	10	~~HS~~ BSW			
	Flue Damper	$2.97	10	HS			
	Wall Insulation	$5.21	15	INS			
	Attic Insulation	$12.09	15	INS			
Infill Properties	DHW Tank Insulation	$9.13	15	WH			
	Clock Thermostat	$0.96	15	HS			
	Flue Damper	$1.67	10	HS			
	Intermittent Ignition	$7.73	10	HS BSW			
	Boiler Reset	$3.03	10	~~HS~~ INS			
Various	Energy Management System	$3.28	15	HS			
Old Colony & Charlestown	Steam Traps	$2.78	5	HS			

Notes:
[1] From Table 4.1
[2] From Table 4.1
[3] Determined by end use
'] From Table 3.4

Table 4.3: SUMMARY OF COST EFFECTIVE BOSTON HOUSING AUTHORITY CONSERVATION MEASURES

DEVELOPMENT	MEASURE	COST [1]	ANNUAL CCF [2]	ANNUAL COST [3]
General Warren	DHW Tank Insulation	$2,500	946	$342.00
	Door Weatherstripping	$8,951	3378	$1,874.34
	Clock Thermostats	$3,192	1229	$436.67
	Flue Damper	$3,528	940	$589.88
	Tighten Windows	$301	87	$63.03
	Intermittent Ignition	$26,784	5626	$4,478.28
	Attic Insulation	$15,573	3716	$2,130.39
	WS Windows	$446	88	$93.39
	New Windows [4]	$29,447	2083	$3,633.76
	New Heat Systems	[5]	[5]	-----
	Insulate Slab	$0	0	$0.00
	Insulate Ducts	$5,858	2097	$801.37
RAP/Rehab	DHW Tank Insulation	$1,083	526	$148.15
	Door Weatherstripping	$1,102	445	$230.76
	Clock Thermostats	$2,736	1933	$374.28
	Tighten Windows	$0	0	$0.00
Gallivan Boulevard	Boiler Reset	$91,390	19805	$15,280.41
	Intermittent Ignition	$68,913	14760	$11,522.25
	Flue Damper	$16,954	9538	$2,834.71
	Wall Insulation	$262,237	68804	$35,874.02
	Attic Insulation	$70,078	7932	$9,586.67
Infill Properties	DHW Tank Insulation	$0	0	$0.00
	Clock Thermostat	$5,718	8136	$782.22
	Flue Damper	$4,698	4700	$785.51
	Intermittent Ignition	$14,141	3060	$2,364.38
	Boiler Reset	$18,232	10062	$3,048.39
Various	Energy Management Syst	$575,000	239583	$78,660.00
Old Colony & Charlestown	Steam Traps	$796,200	765517	$212,983.50
Total		$2,025,062	1174993	$388,918.36
Average Cost ($/MMBTU)				$3.31

Notes:
[1],[2],[3] From Table 4.1, cost-effective measure only
Cost-effective 1989
[5] Not known: up to $70,000 and 4498 ccf

APPENDIX A:

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.

<u>Utility Rate Analyst</u>, 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., <u>The New Electric Power Business</u>, 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 <u>Current Issues Challenging the Regulatory Process</u>, 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:

LEVELIZED COST OF CONSERVATION CALCULATIONS

filename= bgasctcn

COST OF CAPITAL

	Cost	Share	Weighted Share	Weighted Taxes
Debt	9.75%	50%	4.88%	---
Preferred	0.00%	0%	0.00%	0.00%
Common	14.875%	50%	7.44%	4.61%
Total			12.31%	4.61%

TAX RATE:	Federal:	34.00%
	State:	6.50%
	Total:	38.29%(Tottax)
	Inflation Rate:	4.00%(IR)

filename= bgasctcn

LEVELIZED COST OF CONSERVATION PER $100 INVESTED

Life = 5.00 years

Year	Year-end Rate Base [1]	Depreciation [2]	Return [3]	Taxes [4]	Total Cost [5]	Nominal Value of $1 in Year 1$ [6]
0	61.71	---	--	---	---	1.00
1	49.37	12.34	7.60	10.51	30.45	1.04
2	37.03	12.34	6.08	9.94	28.35	1.08
3	24.69	12.34	4.56	9.37	26.26	1.12
4	12.35	12.34	3.04	8.80	24.18	1.17
5	0.01	12.34	1.52	8.23	22.09	1.22
Present Value at Cost of Capital:					95.68	4.45
Present Value of $1:					3.58	
Levelized cost:					26.75	21.52

LEVELIZED COST OF CONSERVATION PER $100 INVESTED

Life = 7.00 years

Year	Year-end Rate Base [1]	Depreciation [2]	Return [3]	Taxes [4]	Total Cost [5]	Nominal Value of $1 in Year 1$ [6]
0	61.71	----	--	---	---	1.00
1	52.89	8.82	7.60	7.56	23.98	1.04
2	44.07	8.82	6.51	6.48	23.98	1.08
3	35.25	8.82	5.43	5.40	23.98	1.12
4	26.43	8.82	4.34	4.32	23.98	1.17
5	17.61	8.82	3.25	3.24	23.98	1.22
6	8.79	8.82	2.17	2.16	23.98	1.27
7	-0.03	8.82	1.08	1.08	23.98	1.32
Present Value at Cost of Capital:					108.34	5.53
Present Value of $1:					4.52	
Levelized cost:					23.98	19.60

filename= bgasctcn

LEVELIZED COST OF CONSERVATION PER $100 INVESTED

Life = 10.00 years

Year	Year-end Rate Base [1]	Depreciation [2]	Return [3]	Taxes [4]	Total Cost [5]	Nominal Value of $1 in Year 1$ [6]
0	61.71	---	--	---	---	1.00
1	55.54	6.17	7.60	6.68	20.45	1.04
2	49.37	6.17	6.84	6.39	19.40	1.08
3	43.20	6.17	6.08	6.11	18.36	1.12
4	37.03	6.17	5.32	5.82	17.31	1.17
5	30.86	6.17	4.56	5.54	16.27	1.22
6	24.68	6.17	3.80	5.25	15.22	1.27
7	18.51	6.17	3.04	4.97	14.18	1.32
8	12.34	6.17	2.28	4.68	13.13	1.37
9	6.17	6.17	1.52	4.40	12.09	1.42
10	0.00	6.17	0.76	4.11	11.04	1.48
Present Value at Cost of Capital:					93.30	6.87
Present Value of $1:					5.58	
Levelized cost:					16.72	13.59

filename= bgasctcn

LEVELIZED COST OF CONSERVATION PER $100 INVESTED

Life = 15.00 years

Year	Year-end Rate Base [1]	Depreciation [2]	Return [3]	Taxes [4]	Total Cost [5]	Nominal Value of $1 in Year 1$ [6]
0	61.71	---	--	---	---	1.00
1	57.60	4.11	7.60	5.40	17.11	1.04
2	53.48	4.11	7.09	5.21	16.42	1.08
3	49.37	4.11	6.58	5.02	15.72	1.12
4	45.25	4.11	6.08	4.83	15.02	1.17
5	41.14	4.11	5.57	4.64	14.33	1.22
6	37.03	4.11	5.07	4.45	13.63	1.27
7	32.91	4.11	4.56	4.26	12.93	1.32
8	28.80	4.11	4.05	4.07	12.24	1.37
9	24.68	4.11	3.55	3.88	11.54	1.42
10	20.57	4.11	3.04	3.69	10.85	1.48
11	16.46	4.11	2.53	3.50	10.15	1.54
12	12.34	4.11	2.03	3.31	9.45	1.60
13	8.23	4.11	1.52	3.12	8.76	1.67
14	4.11	4.11	1.01	2.93	8.06	1.73
15	0.00	4.11	0.51	2.74	7.36	1.80
ent Value at Cost of Capital:					91.61	8.51
Present Value of $1:					6.70	
Levelized cost:					13.68	10.76

filename= bgasctcn

LEVELIZED COST OF CONSERVATION PER $100 INVESTED
Life = 20.00 years

Year	Year-end Rate Base [1]	Depreciation [2]	Return [3]	Taxes [4]	Total Cost [5]	Nominal Value of $1 in Year 1$ [6]
0	61.71	---	--	---	---	---
1	58.62	3.09	7.60	4.76	15.45	1.00
2	55.54	3.09	7.22	4.62	14.92	1.04
3	52.45	3.09	6.84	4.48	14.40	1.08
4	49.37	3.09	6.46	4.34	13.88	1.12
5	46.28	3.09	6.08	4.19	13.36	1.17
6	43.20	3.09	5.70	4.05	12.83	1.22
7	40.11	3.09	5.32	3.91	12.31	1.27
8	37.03	3.09	4.94	3.77	11.79	1.32
9	33.94	3.09	4.56	3.62	11.27	1.37
10	30.85	3.09	4.18	3.48	10.75	1.42
11	27.77	3.09	3.80	3.34	10.22	1.48
12	24.68	3.09	3.42	3.20	9.70	1.54
13	21.60	3.09	3.04	3.05	9.18	1.60
14	18.51	3.09	2.66	2.91	8.66	1.67
15	15.43	3.09	2.28	2.77	8.13	1.73
16	12.34	3.09	1.90	2.63	7.61	1.80
17	9.26	3.09	1.52	2.48	7.09	1.87
18	6.17	3.09	1.14	2.34	6.57	1.95
19	3.09	3.09	0.76	2.20	6.04	2.03
20	0.00	3.09	0.38	2.06	5.52	2.11
Present Value at Cost of Capital:					90.39	9.45
Present Value of $1:					7.33	
Levelized cost:					12.34	9.57

filename= bgasctcn

Notes:

[1]: year 0= 100*(1-TotTax)
     subsequent years= [1](t-1)-[2]
[2]: [1](t-1)/Life
[3]: [1](t-1)*Cost of Capital
[4]: [1](t-1)*TotTax+[3]*(1/(1-TotTax)-1)
[5]: [2]+[3]+[4]
[6]: [6](t-1)*[1+IR]
t=year

APPENDIX C:

ASSESSING CONSERVATION PROGRAM COST-EFFECTIVENESS
PARTICIPANTS, NON-PARTICIPANTS, AND THE UTILITY SYSTEM

PROCEEDINGS OF THE FIFTH
NARUC BIENNIAL REGULATORY INFORMATION

CONFERENCE

VOLUME 3

The National Regulatory Research Institute
September 3-5, 1986

ASSESSING CONSERVATION PROGRAM COST-EFFECTIVENESS PARTICIPANTS, NON-PARTICIPANTS, AND THE UTILITY SYSTEM

Ann Bachman
Policy Unit
Massachusetts Executive Office of Energy Resources
Boston, Massachusetts

Paul Chernick
PLC, Inc.
Boston, Massachusetts

Introduction

Utility regulators have increasingly been asked to rule on issues related to utility-sponsored conservation programs. Utilities have requested prior approval, and in some cases prior funding, of proposed programs. Other utilities have examined a range of programs, have chosen not to implement many or most of them, and have requested regulatory approval of those decisions. Intervenors have argued that additional programs should be funded, or that the scope or incentives of existing programs should be increased. All of these questions force regulators to face the issue of selecting an evaluation methodology for conservation investments.

The planning of conservation programs for energy utilities requires the assessment both of the relative cost-effectiveness of specific conservation options and of the cost-effectiveness of the overall conservation program, compared to other sources of power supply. There is considerable controversy within the utility industry on how to make these evaluations. One school of thought holds that all conservation measures which are less expensive than the utility's incremental costs of supply are cost-effective and should be funded. Another school holds that the correct criterion for investment in conservation is that the conservation program reduce the utility's average cost per unit of sales. This latter criterion is generally assumed to require that the cost of the conservation program be less than the utility's differential cost, defined as the difference between the company's marginal and average costs of supply.

These two views show a wide divergence in a critical area of decision-making in the industry. That such disparity can exist should not be surprising if we consider that the two schools represent different utility goals with respect to conservation planning, as well as differing perspectives on the customer side. This paper will examine the problem of evaluating the cost-effectiveness of conservation investments by utilities from three perspectives:

the customers who participate in the program, the customers who do not participate, and the utility system (the utility and its customers) as a whole. The examples are expressed in terms of the units, cost structure, and conservation options of an electric utility, but the same considerations apply to gas service, as well.

The analysis uses specific numerical examples to show from the three perspectives, the effect on conservation economics of the utility's incremental costs (including the distinction between existing and new sources of supply), and the cost of conservation. In this way, the examples illustrate the relationships between current average cost, the cost of new supply, and the cost of conservation. In addition to the static case type of analysis, dynamic situations are presented in which costs change over time. The numerical examples were developed to show conservation economics within archetypical utility supply and cost contexts: capacity-rich utilities, capacity-short utilities, utilities with very low average costs and high incremental costs, and utilities with high average and low incremental costs.

Before presenting the numerical examples, it is important to explain what we mean by conservation. From a customer's point of view, there are approximately four categories of conservation. First, there is conservation from more efficient appliances or installations (e.g., water heater wrap) that require no customer life-style or behavior change. Building retrofit or new construction that results in improved building thermal efficiency provides energy and demand savings of this kind. A second type of conservation can be achieved by installing devices that require minimal changes of service but no on-going significant effects or customer involvement. Screw-in fluorescent bulbs provide conservation of this kind: the light is slightly different from that of an incandescent, and may represent a small gain or small loss in utility, depending on the application and user preferences. Third, there are installations through which the same basic end-use service is available but some thought by the customer is required if conservation is to result. This kind of conservation comes from devices such as set-back thermostats, anti-sweat switches on refrigerators, and the cold-dry switch on dishwashers. Finally, there are actions that consumers can take to effect conservation that involve substantial life-style changes and degrees of altered service. Turning thermostats down and lights off and washing clothes on cold-water cycles are examples of such customer actions.

From a utility's point of view, the preferred energy and demand savings are those that come on-line, so to speak, like the more traditional supply alternatives: that is, they can be achieved in substantial quantity on a predictable schedule and operate with reasonable reliability. Therefore, the utility's priority savings are those that can be achieved through installations alone with minimal changes in service or requirements in terms of customer behavior.

This is the kind of conservation we assume is being purchased by the utilities in the analysis presented in this paper.

Views on Evaluating Utility Conservation Investments

As noted above, there are two clearly divergent views on how to evaluate the cost-effectiveness of utility conservation nvestments. These two approaches are described below with special reference to utility goals and customer perspectives.

Incremental Cost Approach. From this point of view, utility conservation programs are cost-effective if they produce savings at costs less than the utility's incremental costs of supply. The utility goal that is met when this criterion is applied is the minimization of the total cost of providing heat, light and other energy services. The societal goal being met is the efficient allocation of resources. From the customer's perspective, customers as a group will benefit if rates are based on cost of service, since total costs are minimized. Individual customers may benefit or not depending on their participation and on certain cost and growth characteristics of their utility. It is these relationships which will be explored in the numerical examples presented in this paper.

Average Cost Approach. From this viewpoint, utility investments in conservation are cost-effective if they reduce the utility's average cost of service and hence the average rates which must be charged to make the utility whole. Another utility goal that is often mentioned when this criterion is applied is protection of the non-participant. The non-participant is any customer who, for any reason, does not participate in utility conservation programs. While non-participants would not benefit directly from a utility conservation investment, the Average Cost Approach insists that they not be penalized by higher rates resulting from the combination of utility expenditures on conservation and lost sales to the participating customer. Thus, the Average Cost test is essentially identical to the "no-losers" test, which has been rejected by some regulators. The Average Cost test can be applied to long-term costs (perhaps out to the utility's planning horizon), or to the short-term effects (perhaps as short as the rate year), and may produce very different results for different time frames.

These two approaches together represent the perspectives of the three main actors in this drama: the utility (taken to mean its customers as a group), customers who participate in utility conservation rograms, and customers who do not participate. And yet, clearly, the two evaluation tools cannot both be correct. The numerical examples presented in this paper show, for a very simple utility system, just how each of these groups are affected by utility conservation investments under varying conditions of utility embedded and marginal costs and demand growth.

It is important to note that all of our cases assume that the utility makes the entire cash outlay required to implement the conservation program, so that no costs are borne directly by the participating customer. In addition, we have assumed that the utility will recover all costs of the conservation program, as well as the revenues which would have been lost through conservation. The mechanisms applied to make utilities whole will vary between jurisdictions, depending on a number of legal and policy considerations. One of us has previously described a framework for stabilizing utility revenue streams despite large conservation effects.

Effects of Conservation with High Marginal Costs

The Base Case and High Growth Scenario

The base case utility has three customers each using energy supplied to them at an average cost of 10 cents/kWh. Since our utility has fully cost-based rate structures we can assume that the total costs to the customer are analogous to the prices facing him; and that the total cost figures are therefore the bills that customers received for the time period. Table 1 shows the effect on average

TABLE 1: New Construction at 18 Cents

Assumptions	Customers 1	2	3	Total	Average
Assume 3 customers:					
Each using	10,000	10,000	10,000	30,000 kWh	
At a cost of	$1,000	$1,000	$1,000	$3,000	$0.100 /kWh
20% Growth					
Assume 20% growth in consumption	2,000	2,000	2,000	6,000 kWh	
At $0.180 /kWh					
for a total marginal cost to serve of	$1,360	$1,360	$1,360	$4,080	
total consumption of	12,000	12,000	12,000	36,000 kWh	$0.113 /kWh

costs when the utility, and each of its customers, experiences 20% growth in consumption. In this case, load growth is not moderated by conservation, so new generation is brought on-line to serve the new demand at an incremental cost of 18 cent/kWh. This figure approximates the cost of power from nuclear power plants currently entering service, and from the coal plants projected by some utilities for the 1990's. The effect on average costs is to increase average costs from 10 cents/kWh to 13 cents/kWh. Each of the three customers experiences the same level of increased consumption, and so face the same costs for the time period.

For ease of presentation, the incremental cost has been described as the cost of a new plant to meet load growth. The analysis presented in this paper is equally valid if applied to reductions in current load levels through conservation, and where the incremental source of power is an existing plant, rather than a new one.

The Conservation Cases

Consider the case, shown in Table 2, in which the 20% growth in

TABLE 2: Conservation at 5 Cents

Assumptions	Customers 1	2	3	Total	Average
Assume 3 customers:					
Each using	10,000	10,000	10,000	30,000 kWh	
At a cost of	$1,000	$1,000	$1,000	$3,000	$0.100 /kWh
20% Growth Replaced by Conservation					
Assume 20% growth is avoided by conservation of	2,000	2,000	2,000	6,000 kWh	
At $0.050 /kWh					
for a total marginal cost to serve of	$1,100	$1,100	$1,100	$3,300	
total consumption of	10,000	10,000	10,000	30,000 kWh	$0.110 /kWh

consumption is entirely avoided by conservation which costs the utility 5 cents/kWh. This figure is purely illustrative: 5 cents/kWh is a relatively high figure for the cost of utility conservation programs, and substantial savings are usually possible for a few mills/kWh. Each of the three customers participates in the conservation programs, the cost of which increase average costs from 10 cents/kWh to 11 cents/kWh. Obviously, both the customers and the company are better off than in the high growth case since total costs for the utility and each of its customers are lower. The conservation case shown in Table 3 represents a more realistic situation.

TABLE 3: Mixed Case (Some Conservation/Some Growth)

Assumptions	Customers 1	2	3	Total	Average
Assume 3 customers:					
Each using	10,000	10,000	10,000	30,000 kWh	
At a cost of	$1,000	$1,000	$1,000	$3,000	$0.100 /kWh

Some Conservation/Some Growth

Assume 20% growth is avoided by conservation of	2,000	1,000	0	3,000 kWh	
At $0.050 /kWh					
and met with new sources of		1,000	2,000	3,000 kWh	
at $0.180 /kWh					
for a total marginal cost to serve of	$1,100	$1,230	$1,360	$3,690	
total consumption of	10,000	11,000	12,000	33,000 kWh	
					$0.112 /kWh
Bills at average cost =	$1,118	$1,230	$1,342	$3,690	

In this case, the utility avoids half of the 20% growth in consumption through investment in conservation programs: the resulting 10% growth in demand is met with new sources at 18 cents/kWh. One of the three customers participates fully; the second moderates his growth in consumption; and Customer No. 3 does not participate. From a customer's perspective, this non-participant faces bills only slightly higher than participating customers but is still better off than when the company's growth in demand was entirely unmanaged. The non-participant should therefore welcome the utility's conservation investments even though he does not benefit directly. Also, the non-participant's bill, which is based on an average cost (11.2 cents/kWh) that is lower by other customers' efforts to conserve, is actually $18 less than the marginal cost to serve him.

If a subsidy is taking place among customers, it is the participating customer who is subsidizing the non-participant since the participating customers bill is $18 more than the marginal cost to serve him. The utility is better off than in the high growth case because its total costs are lower. This cancels the effect of selling fewer kilowatt-hours and results in a lower average cost.

Effects of Conservation with Low Marginal Costs

Tables 4 and 5 show two growth/conservation scenarios for a utility

TABLE 4: New Construction at 9 Cents

Assumptions	Customers 1	2	3	Total	
Assume 3 customers:					
Each using	10,000	10,000	10,000	30,000 kWh	
At a cost of	$1,000	$1,000	$1,000	$3,000	
20% Growth	**Customers 1**	**2**	**3**	**Total**	**Average**
Assume 20% growth in consumption	2,000	2,000	2,000	6,000 kWh	
At $0.090 /kWh					
for a total marginal cost to serve of	$1,180	$1,180	$1,180	$3,540	
total consumption of	12,000	12,000	12,000	36,000 kWh	
and an average cost of	$0.098	$0.098	$0.098		$0.098 /kWh

with relatively inexpensive sources of new power. At incremental costs of 9 cents/kWh, these would be new peaking units of life extensions. In the case presented in Table 4, the unmanaged growth in consumption is supplied at a marginal cost of 9 cents/kWh. When average with 10 cents/kWh of resources to meet existing demand, average costs fall to 9.8 cents/kWh. The conservation case, with conservation at 5 cents/kWh avoiding growth completely, is identical to the conservation case shown in Table 2.

The most interesting comparison is with the managed growth case shown in Table 5.

TABLE 5: Some Conservation/Some Growth

Assumptions	Customers 1	2	3	Total	Average
Assume 3 customers:					
Each using	10,000	10,000	10,000	30,000 kWh	
At a cost of	$1,000	$1,000	$1,000	$3,000	$0.100 /kWh
Some Conservation/Some Growth					
Assume 20% growth is avoided by conservation of	2,000	1,000	0	3,000 kWh	
At $0.050 /kWh				$0	
and met with new sources of		1,000	2,000	3,000 kWh	
at $0.090 /kWh				$0	
for a total marginal cost to serve of	$1,100	$1,140	$1,180	$3,420	
total consumption of	10,000	11,000	12,000	33,000 kWh	
					$0.104 /kWh
Bills at average cost =	$1,036	$1,140	$1,244	$3,420	

With conservation at 5 cents replacing half of the new supply at 9 cents, average costs are 10.4 cents/kWh. In this case, the non-participating customer is worse off with the conservation program in effect: his bill at the average cost of 10.4 cents/kWh is higher than the utility's cost to serve him, and higher than it would be in the high growth case. The participating customer, on the other hand, pays less than the cost of service. The utility system as a whole is better off with managed growth because, even though sales are down and averaged costs are up with conservation mitigating growth, utility total costs (including the cost of the conservation program) are lower than in the 20% growth case.

These two cost cases raise the interesting question: under what circumstances will the average cost of service decline due to a utility conservation program? This question is answered in the Appendix to this paper, which demonstrates that conservation programs lower average cost when the unit cost of conservation is less than the differential cost times the ratio of sales with conservation to sales without conservation. One interesting implication of this result is that a large conservation program is more likely to raise average unit costs than is a small one, even if the cost of conservation and the displaced energy do not vary between the two programs.

Dynamic Cases

The preceding static analyses are highly over-simplified, and leave some important issues unresolved. For example, some utilities are facing "rate shock" situations due to the completion of major generating facilities: are higher sales particularly beneficial during the period of rate shock to moderate the increase in rates? Similarly, what are the implications for conservation economics if marginal costs are low in the short run, but high in the longer term?

We have developed four dynamic examples to explore these issues. Table 6 presents a simulation of the rate effects of a continuing conservation program, for a utility with fairly high embedded costs, and with incremental costs of traditional power supplies which are low initially but rise rapidly. The costs of conservation are assumed to be paid the year before the conservation is effective. In this situation, the conservation program saves money for the customers as a whole, earning a 78% rate of return, but increases the average unit cost of power.

Table 7 repeats the simulation for Table 6, but with lower embedded costs. Since embedded costs are lower than in Table 6, the conservation program produces smaller increases in the initial average cost, and is eventually able to reduce the average cost of power. The total savings are identical to those in Table 6. The very low

TABLE 6: DYNAMIC ANALYSIS 1, GRADUAL INCREASE IN PRODUCTION COSTS,
CONTINUED CONSERVATION AT 5 CENTS (All Costs in Thousands)

		Conventional Supply			Conservation Program Sized to Maintain Present Load Level				Savings From Conservation Programs Compared to Conventional Supply	
Year	"Natural" Load Growth	Incremental cost of Generation $/kWh	System Cost @ "Natural" Load	Average Cost/ kWh	Conserve Costs @ $0.05 /kWh	System Cost @ 1986 Load	Total Costs	Average Cost/ kWh	Total Costs	Average Cost/ kWh
1986	300,000	$0.03	$27,000	$0.090	$375	$27,000	$27,375	$0.091	($375)	($0.001)
1987	307,500	$0.04	$28,300	$0.092	$750	$28,000	$28,750	$0.096	($450)	($0.004)
1988	315,000	$0.06	$30,900	$0.098	$1,125	$30,000	$31,125	$0.104	($225)	($0.006)
1989	322,500	$0.08	$33,800	$0.105	$1,500	$32,000	$33,500	$0.112	$300	($0.007)
1990	330,000	$0.10	$37,000	$0.112	$1,875	$34,000	$35,875	$0.120	$1,125	($0.007)
1991	337,500	$0.12	$40,500	$0.120	$2,250	$36,000	$38,250	$0.128	$2,250	($0.008)
1992	345,000	$0.14	$44,300	$0.128	$2,625	$38,000	$40,625	$0.135	$3,675	($0.007)
1993	352,500	$0.16	$48,400	$0.137	$3,000	$40,000	$43,000	$0.143	$5,400	($0.006)
1994	360,000	$0.18	$52,800	$0.147	$3,375	$42,000	$45,375	$0.151	$7,425	($0.005)
1995	367,500	$0.18	$54,150	$0.147	$3,750	$42,000	$45,750	$0.153	$8,400	($0.005)
1996	375,000	$0.18	$55,500	$0.148	$4,125	$42,000	$46,125	$0.154	$9,375	($0.006)
1997	382,500	$0.18	$56,850	$0.149	$4,500	$42,000	$46,500	$0.155	$10,350	($0.006)
1998	390,000	$0.18	$58,200	$0.149	$4,875	$42,000	$46,875	$0.156	$11,325	($0.007)
1999	397,500	$0.18	$59,550	$0.150	$5,250	$42,000	$47,250	$0.158	$12,300	($0.008)
2000	405,000	$0.18	$60,900	$0.150	$5,625	$42,000	$47,625	$0.159	$13,275	($0.008)
2001	412,500	$0.18	$62,250	$0.151	$6,000	$42,000	$48,000	$0.160	$14,250	($0.009)
2002	420,000	$0.18	$63,600	$0.151	$6,375	$42,000	$48,375	$0.161	$15,225	($0.010)
2003	427,500	$0.18	$64,950	$0.152	$6,750	$42,000	$48,750	$0.163	$16,200	($0.011)
2004	435,000	$0.18	$66,300	$0.152	$7,125	$42,000	$49,125	$0.164	$17,175	($0.011)
2005	442,500	$0.18	$67,650	$0.153	$7,500	$42,000	$49,500	$0.165	$18,150	($0.012)
	450,000									
						Internal Rates of Return			77.97%	

Cost assumptions:

Fixed costs in 1986: $24,000 including 200,000 kWh of production costs

Incremental T&D: $0.01 /kWh

TABLE 7: DYNAMIC ANALYSIS 2, LOWER EMBEDDED COSTS (All Costs in Thousands)

		Conventional Supply			Conservation Program Sized to Maintain Present Load Level				Savings From Conservation Programs Compared to Conventional Supply	
Year	"Natural" Load Growth	Incremental cost of Generation $/kWh	System Cost @ "Natural" Load	Average Cost/ kWh	Conserve Costs @ $0.05 /kWh	System Cost @ 1986 Load	Total Costs	Average Cost/ kWh	Total Costs	Average Cost/ kWh
1986	300,000	$0.03	$15,000	$0.050	$375	$15,000	$15,375	$0.051	($375)	($0.001)
1987	307,500	$0.04	$16,300	$0.053	$750	$16,000	$16,750	$0.056	($450)	($0.003)
1988	315,000	$0.06	$18,900	$0.060	$1,125	$18,000	$19,125	$0.064	($225)	($0.004)
1989	322,500	$0.08	$21,800	$0.068	$1,500	$20,000	$21,500	$0.072	$300	($0.004)
1990	330,000	$0.10	$25,000	$0.076	$1,875	$22,000	$23,875	$0.080	$1,125	($0.004)
1991	337,500	$0.12	$28,500	$0.084	$2,250	$24,000	$26,250	$0.088	$2,250	($0.003)
1992	345,000	$0.14	$32,300	$0.094	$2,625	$26,000	$28,625	$0.095	$3,675	($0.002)
1993	352,500	$0.16	$36,400	$0.103	$3,000	$28,000	$31,000	$0.103	$5,400	($0.000)
1994	360,000	$0.18	$40,800	$0.113	$3,375	$30,000	$33,375	$0.111	$7,425	$0.002
1995	367,500	$0.18	$42,150	$0.115	$3,750	$30,000	$33,750	$0.113	$8,400	$0.002
1996	375,000	$0.18	$43,500	$0.116	$4,125	$30,000	$34,125	$0.114	$9,375	$0.002
1997	382,500	$0.18	$44,850	$0.117	$4,500	$30,000	$34,500	$0.115	$10,350	$0.002
1998	390,000	$0.18	$46,200	$0.118	$4,875	$30,000	$34,875	$0.116	$11,325	$0.002
1999	397,500	$0.18	$47,550	$0.120	$5,250	$30,000	$35,250	$0.118	$12,300	$0.002
2000	405,000	$0.18	$48,900	$0.121	$5,625	$30,000	$35,625	$0.119	$13,275	$0.002
2001	412,500	$0.18	$50,250	$0.122	$6,000	$30,000	$36,000	$0.120	$14,250	$0.002
2002	420,000	$0.18	$51,600	$0.123	$6,375	$30,000	$36,375	$0.121	$15,225	$0.002
2003	427,500	$0.18	$52,950	$0.124	$6,750	$30,000	$36,750	$0.123	$16,200	$0.001
2004	435,000	$0.18	$54,300	$0.125	$7,125	$30,000	$37,125	$0.124	$17,175	$0.001
2005	442,500	$0.18	$55,650	$0.126	$7,500	$30,000	$37,500	$0.125	$18,150	$0.001
	450,000									
					Internal Rates of Return				77.97%	0.54%

Cost assumptions:

Fixed costs in 1986: $12,000 including 200,000 kWh of production costs

Incremental T&D: $0.01 /kWh

internal rate of return on the average cost column indicates that customers whose usage is unaffected by the program will earn a low return on the extra payments they make in early years.

Table 8 further modifies Table 7 by using a lower (and more realistic) cost of conservation: the program is assumed to cost three cents/kWh saved, rather than the five cents previously assumed. This less expensive conservation produces a substantial 30% return on investment, even measured by the average cost, and an excellent 133% return on total costs.

Table 9 explores the rate shock problem, by assuming a 30% permanent increase in costs in 1987, on top of the costs assumed in Table 8. The total savings are identical to those in Table 8, but the higher embedded costs of power in and after 1987 result in higher average costs, and a lower differential between average and incremental costs. As demonstrated in the Appendix, conservation is less likely to reduce average cost when the differential cost is low. Not surprisingly, the rate shock case results in higher unit costs with conservation than without, even though total bills will be lower with conservation.

Conclusions

We have demonstrated that the average cost of service may increase due to a conservation program, even though total bills to all customers, and even the bill of every customer, decreases. Conservation is beneficial to the utility system as a whole -- that is, the sum of the utility and all of its customers -- so long as the cost of conservation lies below the incremental cost of supply. The conditions under which conservation reduces the average cost are much more restrictive: both high embedded costs and large conservation effects tend to cause conservation programs to increase, rather than decrease, unit costs of service.

The Incremental Cost Approach, defined above, is clearly the correct basis for the evaluation of conservation programs from a broad societal viewpoint. Conservation which meets this test will reduce the total cost of service necessary to provide a given level of benefits to consumers, and thus reduce the size of the cost "pie" which must be divided among customers. Some conservation programs which pass the Incremental Cost test will also pass the Average Cost test, but not all.

The Average Cost Approach is not useful for determining whether conservation program are cost-effective, but it is useful in identifying issues relating to equity and to the distribution of costs and benefits. Conservation programs which pass the Average Cost test

TABLE 8: DYNAMIC ANALYSIS 3, LOWER COST OF CONSERVATION, (All costs in Thousands)

		Conventional Supply			Conservation Program Sized to Maintain Present Load Level				Savings From Conservation Program Compared to Conventional Supply	
Year	"Natural" Load Growth	Incremental cost of Generation $/kWh	System Cost @ "Natural" Load	Average Cost/ kWh	Conserve Costs @ $0.03 /kWh	System Cost @ 1986 Load	Total Costs	Average Cost/ kWh	Total Costs	Average Cost/ kWh
1986	300,000	$0.03	$15,000	$0.050	$225	$15,000	$15,225	$0.051	($225)	($0.001
1987	307,500	$0.04	$16,300	$0.053	$450	$16,000	$16,450	$0.055	($150)	($0.002
1988	315,000	$0.06	$18,900	$0.060	$675	$18,000	$18,675	$0.062	$225	($0.002
1989	322,500	$0.08	$21,800	$0.068	$900	$20,000	$20,900	$0.070	$900	($0.002
1990	330,000	$0.10	$25,000	$0.076	$1,125	$22,000	$23,125	$0.077	$1,875	($0.001
1991	337,500	$0.12	$28,500	$0.084	$1,350	$24,000	$25,350	$0.085	$3,150	($0.000
1992	345,000	$0.14	$32,300	$0.094	$1,575	$26,000	$27,575	$0.092	$4,725	$0.002
1993	352,500	$0.16	$36,400	$0.103	$1,800	$28,000	$29,800	$0.099	$6,600	$0.004
1994	360,000	$0.18	$40,800	$0.113	$2,025	$30,000	$32,025	$0.107	$8,775	$0.007
1995	367,500	$0.18	$42,150	$0.115	$2,250	$30,000	$32,250	$0.108	$9,900	$0.007
1996	375,000	$0.18	$43,500	$0.116	$2,475	$30,000	$32,475	$0.108	$11,025	$0.008
1997	382,500	$0.18	$44,850	$0.117	$2,700	$30,000	$32,700	$0.109	$12,150	$0.008
1998	390,000	$0.18	$46,200	$0.118	$2,925	$30,000	$32,925	$0.110	$13,275	$0.009
1999	397,500	$0.18	$47,550	$0.120	$3,150	$30,000	$33,150	$0.111	$14,400	$0.009
2000	405,000	$0.18	$48,900	$0.121	$3,375	$30,000	$33,375	$0.111	$15,525	$0.009
2001	412,500	$0.18	$50,250	$0.122	$3,600	$30,000	$33,600	$0.112	$16,650	$0.010
2002	420,000	$0.18	$51,600	$0.123	$3,825	$30,000	$33,825	$0.113	$17,775	$0.010
2003	427,500	$0.18	$52,950	$0.124	$4,050	$30,000	$34,050	$0.114	$18,900	$0.010
2004	435,000	$0.18	$54,300	$0.125	$4,275	$30,000	$34,275	$0.114	$20,025	$0.011
2005	442,500	$0.18	$55,650	$0.126	$4,500	$30,000	$34,500	$0.115	$21,150	$0.011
	450,000									
						Internal Rates of Return			132.87%	30.4C

Cost assumptions:

Fixed costs in 1986: $12,000 including 200,000 kWh of production costs

Incremental T&D: $0.01 /kWh

TABLE 9: DYNAMIC ANALYSIS 4, RATE SHOCK IN 1987 (All Costs in Thousands)

		Conventional Supply			Conservation Program Sized to Maintain Present Load Level				Savings From Conservation Programs Compared to Conventional Supply	
Year	"Natural" Load Growth	Incremental cost of Generation $/kWh	System Cost @ "Natural" Load	Average Cost/ kWh	Conserve Costs @ $0.03 /kWh	System Cost @ 1986 Load	Total Costs	Average Cost/ kWh	Total Costs	Average Cost/ kWh
1986	300,000	$0.03	$15,000	$0.050	$225	$15,000	$15,225	$0.051	($225)	($0.001)
1987	307,500	$0.04	$20,800	$0.068	$450	$16,000	$20,950	$0.070	($150)	($0.002)
1988	315,000	$0.06	$23,400	$0.074	$675	$18,000	$23,175	$0.077	$225	($0.003)
1989	322,500	$0.08	$26,300	$0.082	$900	$20,000	$25,400	$0.085	$900	($0.003)
1990	330,000	$0.10	$29,500	$0.089	$1,125	$22,000	$27,625	$0.092	$1,875	($0.003)
1991	337,500	$0.12	$33,000	$0.098	$1,350	$24,000	$29,850	$0.100	$3,150	($0.002)
1992	345,000	$0.14	$36,800	$0.107	$1,575	$26,000	$32,075	$0.107	$4,725	($0.000)
1993	352,500	$0.16	$40,900	$0.116	$1,800	$28,000	$34,300	$0.114	$6,600	$0.002
1994	360,000	$0.18	$45,300	$0.126	$2,025	$30,000	$36,525	$0.122	$8,775	$0.004
1995	367,500	$0.18	$46,650	$0.127	$2,250	$30,000	$36,750	$0.123	$9,900	$0.004
1996	375,000	$0.18	$48,000	$0.128	$2,475	$30,000	$36,975	$0.123	$11,025	$0.005
1997	382,500	$0.18	$49,350	$0.129	$2,700	$30,000	$37,200	$0.124	$12,150	$0.005
1998	390,000	$0.18	$50,700	$0.130	$2,925	$30,000	$37,425	$0.125	$13,275	$0.005
1999	397,500	$0.18	$52,050	$0.131	$3,150	$30,000	$37,650	$0.126	$14,400	$0.005
2000	405,000	$0.18	$53,400	$0.132	$3,375	$30,000	$37,875	$0.126	$15,525	$0.006
2001	412,500	$0.18	$54,750	$0.133	$3,600	$30,000	$38,100	$0.127	$16,650	$0.006
2002	420,000	$0.18	$56,100	$0.134	$3,825	$30,000	$38,325	$0.128	$17,775	$0.006
2003	427,500	$0.18	$57,450	$0.134	$4,050	$30,000	$38,550	$0.129	$18,900	$0.006
2004	435,000	$0.18	$58,800	$0.135	$4,275	$30,000	$38,775	$0.129	$20,025	$0.006
2005	442,500	$0.18	$60,150	$0.136	$4,500	$30,000	$39,000	$0.130	$21,150	$0.006
	450,000									
					Internal Rates of Return				132.87%	16.77%

Cost assumptions:

Fixed costs in 1986: $12,000 including 200,000 kWh of production costs

1987 Rate Shock: 30% of 1986 Rates $4,500

Incremental T&D: $0.01 /kWh

will be beneficial to non-participants, and therefore raise no concerns about adverse effects on any group of customers. In fact, non-participants could offer a cash incentive to participants, in addition to the direct costs of the program, and still come out ahead.

It is the programs which pass the Incremental Cost test, but fail the Average Cost test, which will pose the real problems. Consider a situation in which a major conservation program in the industrial class would reduce total costs, but increase the cost allocation (and hence the rates) of small residential customers, some of them quite poor. The opposite situation may also apply: a residential conservation program may be beneficial to the utility system as a whole, but a severe burden on hard-pressed industrial customers. Similar problems may arise within classes: well-to-do suburban residential customers may participate in an air-conditioning rebate program, which increases the bills of lower-income urban customers who could not afford air conditioners in the first place. None of these outcomes is desirable.

There are three basic approaches to avoiding the distributional problems posed by conservation programs which fail the Average Cost test. The first, and by far the most attractive, is to spread the conservation program widely enough that all customers can participate. Significant conservation options exist in virtually all end uses, and certainly in all classes of customers. If all customers participate, the result will be similar to that shown in Table 2, in which every customer's rates increase, but every customer's bills decrease. Of course, there will always be some non-participating customers, even if opportunities exist for all customers to join in the program. So long as the non-participants may be safely assumed to be limited to those customers who are not burdened by their utility bills (either due to high incomes, or limited end uses, or very high efficiency), the resulting revenue shifts do not appear to be inequitable. The second approach is applicable when the conservation program will allow the participation of only a limited set of rate classes, or of identifiable groups within rate classes. The cost allocation and rate design process may be used to isolate conservation-related costs (possibly including lost revenues) within the participating classes: an industrial drive efficiency program can be charged to the industrial class, and a rebate program for efficient central air conditioning can be recovered from the tail block of the residential rate in the summer months.

The third, and least desirable approach, isolates at least some of the costs of the conservation program to the customer whose efficiency is being improved. Many existing programs take this approach: the utility may pay only part of the cost of the efficiency improvement, or charge a small fee for participation, or support the efficiency improvement with a low interest loan instead of an outright grant. Other utilities have employed a variant of the third-party split-savings approach, in which the utility pays for the conservation investment, and charges the customer a fraction of the resulting savings until the cost has been paid off. Great care must be taken in applying this approach, to ensure that it does not discourage economical efficiency improvements, and to avoid excessive administrative costs. For example, a split-savings arrangement is quite feasible for large industrial and commercial conservation projects, where hundreds of thousands of dollars may be invested at a single site: applying this approach to a residential lighting program, with and investment of tens or hundreds of dollars per site, would impose a significant administrative burden.

Regardless of how any equity issues which may arise are dealt with, the fundamental principle is clear: all conservation which passes the Incremental Cost test should be implemented. Utilities (in conjunction with their regulators) have the responsibility to identify measures and programs which pass the test, to implement those programs, and to ameliorate any serious equity issues raised by programs which fail the Average Cost test.

References

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

2. Re Boston Edison Company, Massachusetts Department of Public Utilities 85-271, June 26, 1986.

APPENDIX: DERIVATION OF CONDITIONS UNDER WHICH CONSERVATION REDUCES AVERAGE PRICES

Let: k_b = base kilowatthour sales

k_g = kilowatthour growth without conservation

c_b = cost of service for k_b

c_g = incremental cost of supplying k_g

c_c = cost of avoiding k_g growth through conservation

r_b = base average cost = c_b/k_g

r_g = average cost of serving growth = c_g/k_g

r_c = average cost of conservation = c_c/k_g

R_g = average cost of service after growth

R_c = average cost of service after conservation

Then:

$$R_g = (c_b + c_g)/(k_b + k_g) \qquad (1)$$

and, if all conservation costs are paid by utility and are reflected in rates,

$$R_c = (c_b + c_c)/k_b \qquad (2)$$

If $R_c < R_g$, (3)

$$(c_b + c_c)/k_b < (c_b + c_g)/(k_b + k_g) \qquad (3')$$

Since all terms are positive, (3') implies

$$c_c < (c_bk_b + c_gk_b - c_bk_b - c_bk_g)/(k_b + k_g)$$

and (4)

$$c_c < (c_gk_b - c_bk_g)/(k_b + k_g) \qquad (5)$$

Substituting for the c's

$$r_c k_g < (r_g k_g k_b - r_b k_b k_g)/(k_b + k_g) \qquad (6)$$

and dividing by k_g

$$r_c < (r_g - r_b)\, k_b/(k_b + k_g) \qquad (7)$$

In other words, conservation will produce lower average rates if the unit cost of conservation is less than the product of:

1. The difference between the unit cost of new and existing service and

2. the ratio of usage with conservation to usage without conservation.

Thus, average rates will always increase if marginal costs (r_g) are less than embedded costs (r_b), or even if r_g is less than the sum of embedded costs and the unit cost of conservation (r_c).

The greater the amount of conservation, as measured by the ratio of usage with conservation (k_b) to usage without conservation ($k_b + k_g$), the lower the cost at which conservation will reduce average costs.

APPENDIX D:

REVENUE LOSSES AND OTHER ISSUES IN EVALUATING DEMAND-SIDE RESOURCES: AN ECONOMIC RE-APPRAISAL

BY

JOHN PLUNKETT
PAUL CHERNICK

REVENUE LOSSES AND OTHER ISSUES IN EVALUATING DEMAND-SIDE RESOURCES: AN ECONOMIC RE-APPRAISAL

John Plunkett
Komanoff Energy Associates
Paul Chernick
PLC, Inc.

As utility incentive programs for increasing customer energy efficiency become more widespread, new challenges have arisen to their economic rationale. It is argued that the revenues which utilities lose due to efficiency programs represent the real costs of efficiency measures to customers. Where utilities' current prices exceed their marginal supply costs, utility incentives allegedly induce uneconomical demand-side investments. Proponents of this view include Joskow (1988), Ruff (1987), Mayberry (1987), and Smith (1987), whom we refer to generally as "the critics".

Concern over lost revenues is not new. The "no-losers" test, the "non-participant" test, and the "rate impact" measure of demand-side programs all examine the effect of conservation programs on the average rates paid by utility's other customers. (California PUC and CEC, 1983, 1987) Each test reduces program benefits, measured in terms of avoided marginal costs, by the decline in revenues collected from the conserving customers, since those lost revenues would have to be recovered through higher rates. Where the utility's marginal supply costs are estimated to be below current rate levels, no efficiency incentive program can ever pass the no-losers test: from the viewpoint of reducing rates to non-participants, increased sales would be preferable to conservation. Indeed, this rationale has been used more recently to justify promotional rates. (Plunkett, 1988b)

As is obvious from the names of the tests applied, this earlier criticism of utility conservation programs was based on distributional concerns. The revenue loss from conservation programs allegedly imposes costs because it transfers responsibility for revenue requirements to non-participating customers. Over the past few years, this position has been widely, but not universally, repudiated by regulators. (D.C. PSC, 1988; Wisconsin PSC, 1986; Massachusetts DPU, 1986.) This rejection has been based, in part, on the realization that no comparable "no-loser" test is normally applied in power supply decisions, even though the benefits and costs of different energy sources may be allocated very differently to various groups of customers. Utilities and regulators generally assume that if a supply source is economical for the utility as a whole, rate design can properly distribute costs so that ratepayers are better off with the new source than without it.

Similarly, if efficiency can reduce load for less than it would cost to supply load, some distribution of the costs and benefits of the program should be feasible in order to leave most ratepayers better off. The distribution of benefits can be widened by offering a greater variety of efficiency improvements and delivery schemes to more customers, while the distribution of costs can be altered by re-assigning certain costs either directly to individual participants, or indirectly to the participants' rate class.

However, the new argument for recognizing lost revenues is quite different than that supporting the traditional no-losers test. The new school of thought treats lost revenues as a measure of real costs, which supposedly cannot be eliminated simply by redistributing costs and benefits. This paper re-examines the costs and benefits of utility demand-side options from six economic vantage points: society; the utility's revenue requirements; an individual participant; non-participants; overall participants; and all energy consumers. Insights are offered into the design of utility programs and utility rates for obtaining economical as well as equitable demand-side investments.

1. Resource Misallocation Resulting from the "Payback Gap" Between Customer and Utility Energy Investment Horizons

Opportunities abound for saving electricity with efficiency improvements apparently costing far less than continued consumption at current prices. (Lovins, 1986a) Yet customers routinely decline these investments, accepting only those that pay for themselves within six months to three years. (Department of Energy, 1987) Such behavior reveals that individuals and businesses apply much higher implicit discount rates to prospective energy savings than they do when evaluating returns from other investments. (Northwest Power Planning Council, 1986; Train, 1985; Hausman, 1979) By persistently foregoing efficiency investments that would otherwise reduce electric demand, consumers compel utilities to expand supply. When doing so, utilities choose between supply options with investment horizons extending 30 years into the future using discount rates in the range of 5-6% real (Komanoff, 1987). This disparity between individuals' and utilities' investment horizons constitutes a "payback gap" that leads society to over-invest in electricity supply. (Cavanagh, 1986)

To appreciate how the payback gap between utilities and their customers can cause severe economic distortions, suppose that utilities allocate investment dollars in an inflation-free world using a 6% discount rate. A utility supply project with a 20-year economic life would be accepted if it showed a payback period of about 12 years. (See Table 1.) But typical customers do not make efficiency investments lasting 20 years unless the measures pay for themselves in two years or less. This rapid payback requirement is equivalent to discounting future savings at an annual rate of 64 percent.

TABLE 1. Required Rates of Return Implied By Payback Criteria Under Different Economic Lives

Payback Period	Economic Life of Investment							
	3	5	7	10	15	20	25	30
1	146.5%	159.8%	161.5%	161.8%	161.8%	161.8%	161.8%	161.8%
1.5	68.4%	87.3%	91.2%	92.3%	92.5%	92.5%	92.5%	92.5%
2	33.5%	55.5%	61.3%	63.5%	64.0%	->64.0%<-	64.0%	64.0%
2.5	13.3%	37.2%	44.4%	47.6%	48.6%	48.8%	48.8%	48.8%
3	0.0%	25.1%	33.4%	37.5%	39.0%	39.3%	39.3%	39.3%
4		9.7%	19.4%	24.9%	27.5%	28.1%	28.3%	28.3%
5		0.0%	10.7%	17.2%	20.7%	21.6%	21.9%	22.0%
6			4.6%	11.9%	16.0%	17.3%	17.8%	18.0%
7			0.0%	7.9%	12.6%	14.2%	14.8%	15.1%
8				4.7%	9.9%	11.8%	12.6%	12.9%
9				2.2%	7.8%	9.9%	10.8%	11.2%
10				0.0%	6.0%	8.3%	9.3%	9.9%
12					3.1%	->5.8%<-	7.1%	7.7%
15					0.0%	3.1%	4.6%	5.5%
20						0.0%	1.9%	3.0%

Note: Assumes no inflation.

The disparity between utility and individual customer discount rates prompts another insight: customers impose a high internal markup to the levelized cost a utility would estimate for efficiency resources. To a utility with a 6% (real) discount rate, a levelized 3 cent/kWh payment stream over 20 years is equivalent to (has the same present worth as) a first-year-only payment of 34.4 cents/kWh. Thus, the utility is indifferent to "investing" in the efficiency measure for a capital cost of 34.4 cents/kWh (where the denominator equals the number of kilowatt-hours being saved per year), or paying 3 cents a year at a time for each kWh saved over the 20-year life of the investment.

However, for the consumer, whose 2-year payback requirement reveals her to be operating under an implicit 64% discount rate, the 34.4 cents/kWh up-front cost of the efficiency measure is equivalent to (has the same present worth as) a 20-year payment stream of 22.0 cents/kWh. The markup between the utility's 3 cent/kWh estimate of the cost of the measure and the consumer's implicit 22.0 cents/kWh cost is an astounding 635% in this example.

Likewise, the customer's 635% efficiency markup means that a typical electric rate of 8 cent/kWh would only motivate her to invest in efficiency that to a utility would cost 1 cent/kWh. As long as customers evaluate efficiency measures under stricter investment criteria than utilities employ in selecting supply options, the payback gap will lead customers to under-invest in efficiency and utilities to over-invest in supply.

This gap creates the basic rationale for utilities to become involved in providing significant incentives for conservation of their products. Conservation measures which appear to be very cost-effective from the utility's perspective or from a social-cost perspective are not being implemented by consumers, even when they appear to be much less expensive than the rates the consumers are paying, and thus highly cost-effective. If the conservation is cheaper than utility supply, and the consumer is not doing it on her own because of more stringent payback criteria, then the utility should step in to ensure that it is done before the utility spends additional funds on more expensive supplies. The payback gap or markup can result from a wide variety of considerations, many of which have been identified by the critics themselves:

1. **Access to capital:** This is potentially a major problem for high-priced efficiency improvements, such as insulation of existing buildings and replacement of air conditioners. For many residential customers, the marginal source of financing is a credit card or personal loan, at rates considerably higher than the utility pays. Even if the customer has a contingency fund in a savings account, those funds may not be considered available for an efficiency investment, and the effective source of capital may be an increase in high-cost personal debt, perhaps in the form of slower repayment of an existing credit-card balance, or a larger loan for an automobile purchase. Low-income customers have no access to credit, which can constrain payback periods to anywhere from one year to one month. Of course, many customers would be able to obtain financing at some cost, but the costs of processing small consumer loans is quite high, as Ruff (1988) points out.

While the details differ, the general situation is similar for many larger customers. The payback periods or internal rates of return imposed by corporate management on energy supervisors are generally equivalent to costs of capital in excess of 20%, and frequently much more. Owners of older multi-family housing may face very high loan origination fees to establish clear title (Bleviss 1987).

2. **Institutional barriers:** To landlords and tenants of individually-metered properties, the benefits of efficiency improvements seem to flow to the other party. Future savings from efficiency improvements have not been internalized into rental property values.

3. **Information and search costs:** Consumers must become familiar with the (sometime quite new) technology of high-efficiency products, including their purchase and installation costs, life expectancies, energy savings, operating costs, convenience and comfort levels. They may also, depending on the measure, need to locate potential vendors, installers, and lenders, and determine the costs, cooperativeness, reputations and qualifications of each of these parties.

Indeed, the cost of finding high-efficiency equipment (let alone competent installers and other consumers with experience in using the equipment) may be very high, except in areas where aggressive utility efficiency programs have created a market. For example, electronic ballasts were practically unavailable in Washington, D.C., before the local electric utility began an ambitious lighting efficiency program (Geller, 1987). Where such programs exist, inefficient lighting equipment is becoming scarce, such as in Las Vegas NV and Austin TX (Avery, 1988).

4. **Inconvenience:** Installing efficiency measures and dealing with vendors, installers, and lenders can be daunting for the uninitiated. For residential and small commercial customers, this may pose a very significant cost. The collective nuisance value of arranging visits for estimates and for the actual work, of understanding contract terms and discussing them with the suppliers, of dropping off checks, of supervising the work, and especially of arranging for correction of any problems, may well be more important than the direct monetary costs of efficiency measures. Some installation procedures are inherently noisy, dusty, or otherwise disruptive, and require at least temporary accommodation on the part of the customer.

5. **Loss of value in the ultimate service:** Heating with wood is not the same as heating with electricity, and lighting with compact fluorescents is not always the same as lighting with incandescents. Consumers may consider the energy-efficient alternative to be inferior to the conventional form, either due to the novelty of the efficient alternative, or due to tangible and important differences in the quality of the service.

6. **Risk:** In purchasing energy-efficient equipment, customers face a large variety of technological risks, including the possibilities of having selected the wrong design, sizing, or manufacturer; of getting a bad unit (or installation) of generally appropriate technology; of shorter-than-anticipated equipment life; of poor performance in reliability, comfort, or energy savings. Customers are understandably skeptical regarding vendor claims of efficiency technologies' costs and performance. Resolving this skepticism increases the costs of information. The direct costs of any of these problems are compounded by having to deal with repairs and returns. For example, if a $10 compact fluorescent bulb fails after a week in service, a householder may face an hour or two of effort to retrieve receipts, drive to the store, stand in line, explain the problem to the clerk, and so on.

Consumers also face several non-technical forms of risk. First, they may install conservation measures (e.g., wood stoves and set-back thermostat) and then not use them effectively. Second, changes in utility rate design can undercut the savings from conservation measures: this is particularly important for energy service companies (ESCOs), whose cash flow is largely dependent on the level and design of utility rates. Third, changing rates and conservation options may render the customer's choice suboptimal, and expose the decision-maker to regret and recriminations, from spouse or boss. Fourth, the customer faces the risk of relocating before the conservation measure has paid for itself, and losing some or all of the residual value of the investment.

Continuing to use electricity in familiar ways in familiar equipment poses little or none of these costs to consumers. The utility attends to the financing, the procurement, the installation, and the planning. The utility selects the risks to be taken, and diversifies them as best it can: for many items (gas turbines, fuel contracts, transformer purchases) utilities can provide a great deal of diversification.

2. Lost Utility Revenue as a Proxy for Customer Efficiency Costs

The critics contend that the utility's reduction in revenues due to a conservation program is an important measure of the cost of the program. The basic reasoning behind this assertion is quite simple: the customer is currently choosing to use electricity rather than implement the conservation measure; hence, the "revealed" cost of the measure to the customer must be at least as great as her savings from the measure, i.e., the utility's reduction in revenues.

The critics further argue that, if these costs could be reduced to less than the lost revenues, someone other than the consumer could step in to implement the measure, and could make money by supplying the expertise, financing, and personnel, and then splitting the savings with the customer. That third party could be an ESCO, an unregulated utility subsidiary, or even the utility itself, which has the advantage of already having a billing arrangement with each customer. But if customers cannot be enticed to pay for the measure out of their energy savings, the argument runs, the customer must be assigning some additional cost to the efficient alternative, which is not reflected in engineering or financial calculations. If rates equal or exceed marginal cost, the critics conclude that any measure for which a customer will not agree to pay, must cost that customer more than the marginal cost to the utility. In particular, any rebate, discount, or subsidy to a customer to encourage conservation of a usage which is already priced at marginal cost must be uneconomical.

While this argument raises issues which may be very useful in program design, it is generally overstated. Its fundamental flaw is in ignoring the possibility that utility incentives might lower the non-monetary costs to customers of efficiency investments. Further examination reveals that many of these costs can be reduced by well-designed utility incentive programs.

1. **Access to capital:** Utilities can eliminate this obstacle entirely, depending on the extent of the incentive. If the measure is being given away, there are no loan forms to fill out, no processing and tracking costs.

2. **Information and search costs:** Utilities can screen technologies of high-efficiency products, vendors, installers, and lenders (if necessary) with a single search, which can be much more comprehensive than the typical customer effort, and not much more expensive than the search a large customer might undertake for a much smaller program. In economic terms, information is a public good, costing about the same for one heat pump or 1,000 heat pumps. In addition, the utility can try out technologies, vendors, and installers in test programs, which only very large customers could duplicate. The utility can expect more cooperation from vendors and installers, since it is a continuing source of potential business. Finally, the utility can provide services directly, or through established contractors, eliminating a whole range of choices each consumer would otherwise have to make on her own.

3. **Inconvenience:** The utility can avoid many of these costs by making or simplifying arrangements for installation and by dealing with vendors, installers, and lenders. Customers do not have to worry about getting what they paid for, or understanding the terms of a contract, and experienced utility personnel should be able to verify compliance quite easily. As noted above, suppliers are likely to be cooperative with the utility, and if they aren't they can be replaced, by the

utility if necessary. Some inconvenience, such as having to be home to let the installers in, or listening to power tools as the storm windows go up, is unavoidable.

4. **Loss of value in the ultimate service:** This may be the one area in which the utility is least likely to reduce costs. Even here, there may be some reduction if the utility overcomes resistance due to novelty.

5. **Risk:** In contrast to potential service degradation, this may be the area where utilities can do the most to reduce non-monetary costs of demand-side investments. Utilities can see to it that customers avoid some or all the risks they would face on their own. All risk disappears for the individual customer if she has no investment in the product, i.e., if the utility pays all its costs.

There are many reasons why a utility, by investing in its customers' efficiency investments, also drastically reduces the size of risks it assumes on their behalf. First, the utility's conservation portfolio is so highly diversified that the risk of a single bad item, short life, or poor performance (whether due to the product or due to the customer) is inconsequential. Dealing with repairs and returns is also less of a problem for the utility, as are all dealings with suppliers, due to the utility's size and bargaining power. Changes in rate designs do not affect the economics of the utility's investment, so that risk factor disappears. And while a customer who moves may lose all benefit of the efficiency investment she leaves behind, the utility continues to receive the savings, so uncertainty about customer relocation does not introduce risk for the utility.

Our overall conclusion is that utilities should be very careful in designing programs which may require participants to give up quality of service. Examples would include conversion of electrically heated homes to wood heat, removal of second refrigerators, and possibly conversion of some lighting from incandescent to fluorescent. We are not suggesting that these measures be excluded from consideration, but only that the utilities carefully consider the non-financial costs to the customer. For example, a utility should exercise caution in structuring the incentives in programs for removing customers' old, inefficient second refrigerators. Utilities might reasonably make discarding an old refrigerator as easy as it already is to leave the appliance running in the basement. By reducing the inconvenience cost of conservation, this strategy lets customers compare the value they place on the energy service directly with the cost of obtaining electricity to provide the service.

3. Six Perspectives for Sorting Out Costs and Benefits of Demand-Side Investments

Six different economic perspectives illuminate the relationships between energy efficiency opportunities, utility revenue losses, and economic efficiency. Let us consider a single hypothetical situation from each of these six perspectives.

A utility system expects 10% growth. Reflecting typical utility circumstances, assume that its average costs of 8 cents/kWh exceed its marginal supply costs of 7 cent/kWh. Half of the utility's 1,000 customers have not installed efficiency measures because they require conservation investments to pay for themselves in two years or less. From society's (and utility investment planners') perspective, these measures appear to cost 3 cents/kWh when the equipment and installation costs are amortized over their 20-year economic life using a 6% societal discount rate. If these customers do not install the measures, the utility will have to invest in the supply-side alternative costing 7 cents/kWh. Finally, the utility must decide whether to offer an 80% rebate to participants.

There are six different ways to look at this investment choice, as seen in Figure 1 and Table 2.

1. Societal or Total Resource Cost: From society's standpoint, the demand-side option is clearly preferable. Since the supply-side measure would cost $140,000 to acquire, the $60,000 demand-side resource results in a net benefit of $80,000 if it avoids the supply-side alternative. Combining the 3-cent societal costs of the efficiency measures with the relevant electricity costs indicates the average cost of energy services delivered. This cost declines from 8 cents/kWh before growth, to 7.5 cents/kWh with the demand option (20,000 MWh of electricity at 8 cents/kWh + 2,000 MWh of efficiency at 3 cents/kWh), versus 7.9 cents/kWh under the supply case.

Society's preference for the demand-side option is invariant to all but a relative few assumptions. The only ones of any consequence are (1) the total resource cost of the supply and demand options, including (2) the administrative and marketing costs the utility incurs in order to conduct the program (assumed zero here for simplicity). Factors that society does consider irrelevant to the economic efficiency of the investments include (1) the relative incidence of revenue requirements on participants vs. non-participants, either before or after the program; and (2) the incentive paid to participants. Both these elements represent transfers among the two groups.

2. Utility Revenue Requirements: Utility ratepayers as a whole focus only on the change in revenue requirements associated with each option, or -- equivalently -- average utility bills. Accordingly, they also favor the demand-side option under these assumptions, since 80% of the resource's 3-cent cost equals 2.4 cent, well below the marginal supply cost of 7 cent.

Demand Vs. Supply Options

2-Yr Required Payback, 80% Rebate

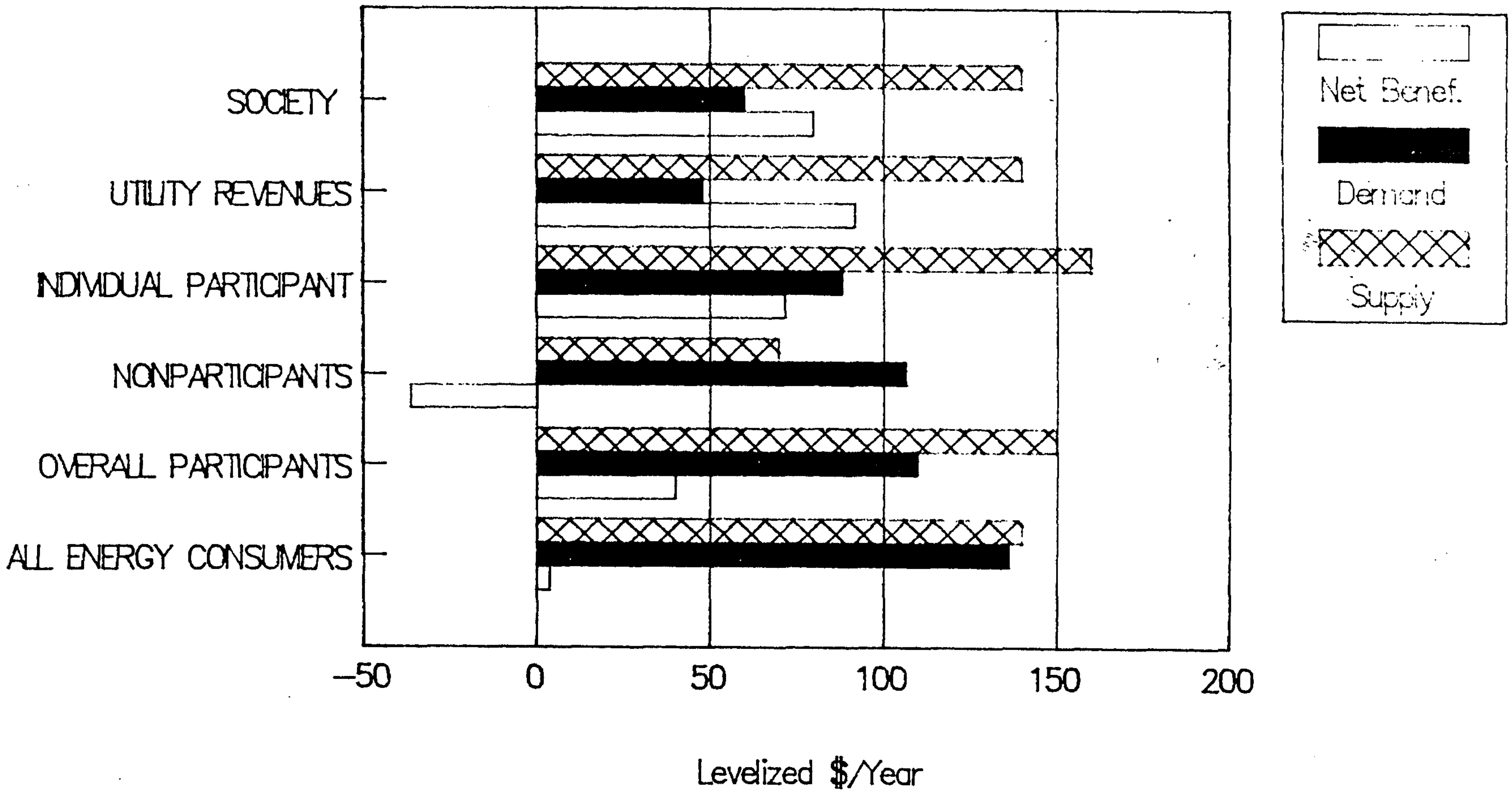

Figure 1

TABLE 2: Economic Comparison of Supply and Demand Options, With 80% Utility Rebate

ASSUMPTIONS

Investment criteria	
Economic life of supply and demand options, years	20
Individual participant's required payback period, years	2
Societal and utility discount rate	6%
Electricity costs, levelized cents/kWh	
Average cost before growth	8.0
Supply-side resource cost	7.0
Demand-side resource cost	3.0
Total customers	1,000
Participants	500
Average annual electricity sales per customer	
Participants	
Before growth, kWh/year	20,000
Growth, %	10.0%
Non-participants	
Before growth, kWh/year	20,000
Growth, %	10.0%

RESULTS

Electricity consumption	Supply Option	Demand Option	Supply - Demand Option Option
TOTAL (MWh/yr)			
Utility ratepayers	22,000	20,000	2,000
Overall participants	11,000	9,000	2,000
Non-participants	11,000	11,000	0
AVERAGE (kWh/customer/yr)			
Utility ratepayers	22,000	20,000	2,000
Overall participants	22,000	18,000	4,000
Non-participants	22,000	22,000	0
Energy service costs			
TOTAL COSTS ($000/yr)			
Society [1]	$1,740	$1,660	$80
All energy-service customers [2]	1,740	1,736	4
Overall participants [2]	870	830	40
Non-participants	870	906	(36)
AVERAGE BILL ($/customer/yr)			
Society [1]	$1,740	$1,660	$80
All energy-service customers [2]	1,740	1,736	4
Overall participants [2]	1,740	1,659	81
Non-participants	1,740	1,813	(73)
AVERAGE UNIT COST (Cents/kWh)	7.91	8.24	-0.33

Notes

1. Using societal discount rate.
2. Using participants' discount rate for costs they incur, and societal discount rate for costs borne by the utitlity.

This perspective is the one utilities ordinarily use to make supply-side decisions. As does the total-resource perspective, the utility revenue-requirements perspective ignores the relationship between participants and non-participants. Unlike society at large, however, utility ratepayers as a whole do consider the rebate incentive as a cost, while ignoring the costs incurred by participants (and thus not included in utility revenue requirements). To ratepayers, incentive payments for demand reductions that would have occurred in the absence of the utility program are wasted, even though to society such costs represent transfers from ratepayers to participants. (See Table 3.)

3. Individual Participant: To an individual participant, the choice is between continuing to use utility kWh at 8 cent/kWh, and investing in an electricity-saving efficiency improvement. Without utility intervention, the individual marks up to apparent cost of the efficiency measure far beyond the price of continued electricity use. These same customers impose no markup on the supply alternative. having no difficulty with "business as usual". But collectively, they force the utility system to expand supply if they fail to pursue demand-side alternatives on their own. The apparent benefit of the demand-side option is $160,000 to all 500 potential individuals, which exceeds the $140,000 benefit to society (since 8-cent rates exceed 7-cent marginal costs in this example). This benefit is also larger than the customer-valued cost of the efficiency measure after the 80% rebate, which is 4.4 cent -- a fifth of the 22-cent cost resulting from the individual's markup, yet still almost 50% more than the 3-cent/kWh resource cost from society's perspective.

The individual participant's perspective is driven primarily by her rapid payback requirement and by the electricity price she pays before undertaking the efficiency measure. This perspective does not consider the broader impact on rates from collective participation of many customers. As shown below, this overall perspective involves the share of the rebates that participants pay themselves, and the

TABLE 3. Effect of Changes in Demand-Side Program on Net Benefits for Different Groups

Net Benefit Change: None, Rise, Fall
Total: Zero, Positive, Negative

Action	Group: Society	Utility Ratepayers	Individual Participant	Non-Participant	Overall Participants	All Energy Consumers
None	None Positive	Rise Positive	Fall Negative	Rise Negative	Fall Negative	Fall Negative
Efficiency standards instead of rebate [1]	None Positive	Rise Positive	Fall Positive	Rise Negative	Rise Positive	Rise Positive
Free riders increase from none to 10%	None Positive	Fall Positive	None Positive	Fall Negative	Fall Positive	Fall Negative
Demand-side bid at 80% of avoided cost, no payback gap, and uneconomical efficiency [2]	Fall Negative	Fall Positive	Fall Positive	Fall Negative	Fall Negative	Fall Negative
Participants charged 5% higher rates than non-participants	None Positive	None Positive	Fall Positive	Rise Positive	Fall Positive	None Positive

Notes
-----

1. Participants are actually better off with standards than the rebate. With the 80% rebate, they pay 20% of a much higher apparent cost, or 4.4 cents/kWh. Standards eliminate the payback gap. Even though they pay all the societal costs, 100% of 3 cents is still less than 20% of 22 cents, the apparent cost of the 3-cent measure.

2. Assumes customers discount future costs and benefits using same rate as utility and society, and that total resource cost of demand-side option is 9 cents/kWh. This implies that customer would choose the efficiency resource over continued consumption; however, the bid implies that the customer pays 38% of the measure's cost, which is less attractive than the 80% rebate.

smaller kWh base over which to spread total utility costs.

4. Non-Participants: Non-participants would prefer the utility to pursue the supply option. Even though utility revenues increase by less with the demand resource than with the supply option, billing units increase under the supply option (22,000 MWh) but stay the same as before demand growth (20,000 MWh). Consequently, the supply side option raises total revenue requirement by less (9%) than the increase in total sales (10%), implying lower average costs and therefore rates per kWh sold (7.9 cents) than before growth (8 cents). Non-participants' consumption would account for a greater share of total electricity sales, and therefore, makes them responsible for a larger share of (the lower total costs after the demand-side resource. Since non-participants' consumption is constant, their bills rise from $1,740/year in the supply scenario to $1,813 in the demand case.

To non-participants, the cost of the demand-side measure is almost irrelevant, since it is overwhelmed by the "cost" of lost revenue collection. Even if the demand-side measure were "free" to the utility -- that is, paid entirely by participants -- they will still favor the supply option whenever it can be obtained at less than average cost. (See Table 3) In this case, conservation is a zero-sum game for non-participants. Without reallocating cost responsibility, it would take an extremely expensive supply option to make non-participants favor demand-side investment (Plunkett, 1987).

5. Overall Participants: This "second look" through the eyes of participants modifies their first look -- perspective 3 -- to reflect the increase in rates the participants precipitate by acquiring the demand-side measures and therefore reducing growth in sales. In effect, this is a global perspective that reflects the full impact of participants' collective actions on their future rates.

As discussed above, each incremental participant perceives the benefit of conservation in terms of the current 8-cent average cost before growth. However, collectively taking advantage of the efficiency opportunity has two added "costs" that are unforeseen by the individual. The first is that, like non-participants, each participant foregoes lower average costs. Paradoxically, when average costs exceed marginal costs, participants' collective inaction ultimately lowers rates while raising average electricity bills (7.9 cents/kWh and $1,740/year in the supply case, vs. 8.2 cents/kWh and $1,648/year with the demand resource). Second, participants overall end up shouldering much of the cost (half, in our example) of the rebates that individual participants receive.

6. <u>All Energy Consumers</u>: The final perspective considers all energy-service customers together by combining the perspectives of non-participants with that of participants overall. Put another way, this is equivalent to combining the value placed on costs and benefits by the utility revenue-requirements perspective, with that placed on demand-side costs by individual participants. In this case, the benefit of avoiding the $140,000 supply acquisition just barely offsets the combination of (1) the utility's rebate costs and (2) the high internal costs to participants of investing in demand-side resources, even after rebates.

The net benefit of the rebate to all energy consumers is just the difference between total energy service costs with the supply option versus the demand resource -- including the participants' own marked-up contribution to the efficiency resource's cost. Accordingly, it indicates whether participants' apparent well-being has increased enough to offset the decrease in non-participants' welfare. The foregone rate decrease that is sacrificed with diminished sales represents a transfer between groups and therefore cancels out.

4. Bridging the Payback Gap While Preventing Uneconomic Conservation and Promoting Distributional Equity

The individual customer's economic perspective reveals the payback gap to be the major obstacle to least-cost energy services for society and ratepayers at large. Utilities may be able to undercut the short payback requirement in two basic ways: One is to pick up some or even all of the monetary costs of the measures themselves, as in the rebate example just discussed. Another is to reduce non-monetary costs of efficiency measures without necessarily reducing the direct costs of the measures. For example, utilities can restructure the pricing of demand-side measures by altering the customer payment pattern, (e.g., offering extended loan terms at the utility's cost of capital).

Two other problems remain. One concerns the economic efficiency of demand-side measures engendered by utility incentive programs; the other involves the equity of the distribution of costs and benefits of demand-side investments between customers. We address these two difficulties in turn.

A. Lost Revenues and the Potential for Uneconomic Efficiency Investments

The critics of utility conservation programs often fret that the utility's investments will be in the form of incentives that would raise the ratepayer's total reward for conservation to uneconomical levels, i.e., to more than marginal cost. (Ruff, 1987; Joskow, 1988) The critics appear to have two bases for their conclusions. The first is the concept of "bidding for negawatts," in which the utility purchases conservation services from any party that can deliver the savings, and leaves the selection of technologies and delivery mechanisms generally to the provider. (Lovins, 1986?) The second basis is the assertion that rates for most utilities equal or exceed marginal costs, so that any conservation incentive above and beyond existing rates would thus increase the customers' total incentive to conserve to more than marginal cost.

Regarding demand-side bidding, it should be noted that its advocates are often vague in their discussions of procurement policies. In general, proponents of demand-side bidding do not intentionally advocate paying more than avoided marginal costs for conservation (although there are differing opinions as to what constitutes the avoided cost), but they do tend to be a bit imprecise in distinguishing between what the utility pays and what society pays.

Critics of demand-side bidding hastily conclude that it overpays for efficiency by confusing two types of utility-sponsored conservation programs. The first type, which the critics assume is the standard, is a hands-off conservation program, in which the utility offers to purchase conservation, without examining the economics of the conservation measures. In the simplest form of hands-off program, the utility posts a fixed price per kWh of conservation, the conservation provider (which may be a customer, or a third party) need merely demonstrate that the conservation occurred, and the utility pays the posted rate times the reduction in sales. Evaluation of conservation program economics is performed entirely by the marketplace. The scheme can be further modified to allow for bidding on price, and to reflect the time-of-use and load factor characteristics of the loads conserved. See Chernick (198xx) for a description of such a program.

Critics are correct that hands-off conservation programs can produce incentives for conservation that exceed the utility's marginal cost. (See Table 3 for an example) Chernick (198xx) has therefore recommended that such programs be used only where marginal costs exceed rates, and that successful bidders receive no more than utility marginal costs. The Maine PUC uses another approach for ensuring that utilities acquire only economical demand-side resources. Demand-side bidders in Maine cannot negotiate shared-savings payments from <u>customers</u> that exceed the difference between the utility's marginal cost and the payment they negotiate from the <u>utility</u>. For example, an ESCO that negotiates a payment from the utility at 80% of 7-cent avoided cost (i.e., 5.6 cents) may not negotiate more than 1.4 cents in shared savings from the customer (i.e., 17.5% of the 8-cent customer savings). While imperfect, this mechanism should minimize incentives for ESCOs to install uneconomic efficiency improvements. (Maine PUC, 1987)

In fact, these limitations may be overly restrictive, given the prevailing payback gap between utility and customer investment decisions: since customers impose high markups on the costs of efficiency measures, typical participants would probably require a total incentive (rates plus conservation incentives) several times as great as utility marginal cost, just to invest in conservation up to the utility's marginal cost. As a first approximation, therefore, regulators and utilities could deem customers' rapid payback requirements as a <u>necessary condition</u> (as well as sufficient cause) for intervening in the market with direct incentives such as rebates.

On the other hand, lost utility revenues --price signals -- alone may sometimes be enough to induce uneconomical investment by some customers. For example, utilities increasingly face "uneconomic bypass." Small-scale cogeneration vendors market power directly to commercial customers at prices slightly below high utility electric rates, profiting while overcoming the customers' payback gap. Where rates exceed marginal supply costs, such arrangements are uneconomical for society.

Utilities can take steps to avoid overpaying for demand-side resources. Utilities should offer incentives only for measures which pass a societal test for cost-effectiveness. (Plunkett, 1988a) Whether these measures are provided by the utility or any other party, utilities should screen incentive payments on the basis of site-specific energy analyses using a total-resource or societal perspective. With this hands-on evaluation approach, the measures installed will, at least on average, provide economical savings to the utility and society.

Of course, even with hands-on evaluation, individual installations may not be cost-effective, especially where the utility has the most limited role in design and cost-effectiveness evaluation. Some efficient lighting will end up in closets, and some customers will buy high-efficiency air-conditioners that they use only rarely. Such eventualities need to be kept in their proper perspective. Far more damaging mistakes have occurred on the supply side. The challenge for utilities and regulators is to minimize the recurrence of such errors by carefully monitoring, evaluating, and adjusting demand-side acquisitions in the future.

B. Redistributing the Benefits of Demand-Side Programs

Critics of rebates and other incentive programs argue that the only demand-side strategy utilities need is a strong price signal -- i.e., tariffs that accurately reflect utility marginal costs. Utilities that have followed this rule probably have highly inequitable demand-side programs, since only customers with ready access to capital and good information on electricity substitutes have participated so far. Utilities can use demand-side programs to balance the distribution of benefits from conservation investment while minimizing costs.

Aside from improving customer access to demand-side programs, utilities can alter the distribution of benefits from such programs by using rate design to reallocate costs and benefits between and within customer classes. Lovins and XXX point out that many efficiency measures yield enough savings to share with utility stockholders, even after participants and non-participants have benefited. (Lovins and XXX, 1986b).

The payback gap adds to the feasibility of using rate design to benefit non-participants while preserving participant interest in demand-side programs. Because of their extremely short payback requirements, participants place a heavy discount on future savings. This implies that the benefits participants perceive from efficiency measures are insensitive to modest increases in future rates. Table 3 illustrates how partially re-assigning revenue responsibility to participants can mitigate or reverse adverse impacts on nonparticipants.

Bibliography

Avery, D., Presentation at the National Association of Regulatory Utility Commissioners Least-Cost Planning Conference, Aspen, CO, April 16, 1988. (Proceedings forthcoming)

Bleviss, D., Testimony on Behalf of the District of Columbia Public Service Commission, Formal Case 834 Phase 2, February, 1987.

California Public Utilities Commission and California Energy Commission, "Standard Practice for Cost-Benefit Analysis of Conservation and Load Management Programs", Joint Staff Report February 1983, Appendix E.

California Public Utilities Commission and California Energy Commission, "Standard Practice Manual for Cost-Benefit Analysis of Demand-Side Management Programs", Joint Staff Report, Draft, August, 1987.

Cavanagh, R.C., "Least-Cost Planning Imperatives for Electric Utilities and their Regulators", Harvard Environmental Law Review, 10(2), 1986.

Chernick, P.L., XXXX, 1987

D.C. Public Service Commission, Opinion and Order, Formal Case No. 834, Phase II, In the Matter of Application of Potomac Electric Power Company for Changes in Electric Rate Schedules, March 15, 1988.

Geller, H.S., Direct Testimony on Behalf of the D.C. People's Counsel, Formal Case 834 Phase II, April 1987.

Hausman, J.A., "Individual Discount Rates and the Purchase and Utilization of Energy-Using Durables", Bell Journal of Economics, 1979.

Joskow, P.xx., Testimony before the U.S. House of representatives Subcommittee on Energy and Power, xx 1988.

Komanoff, C., Testimony on Before the Council of the City of New Orleans Regarding the Prudence of Louisiana Power and Light Management, Ex Parte Application of LP&L for an Increase in Retail Electric Rates, Docket No. CD-86-11, November 1987.

Lovins, A.B., "Gigabucks for Negawatts", Public Utilities Fortnightly, XXX.

__________ and XXXX, Invited Response to Testimony of Ken Costello, Electric Potential, July 1986.

____________, "Advanced Electricity-Saving Technologies and the South Texas Project", Rocky Mountain Institute, December 1986.

Maine Public Utilities Commission, Chapter 38 Regulations, 1987.

Massachusetts Department of Public Utilities, Decision and Order, DPU 85-266-A/85-271-A, 26 June 1986

Mayberry, xx, Testimony on Behalf of Potomac Electric Power Company, DCPSC 834, Phase II, xx 1987.

Northwest Power Planning Council, 1986 Northwest Conservation and Electric Power Plan, 1986.

Plunkett, J., "Saying No to the No-Losers Test: Correctly Assessing Demand-Side Resources to Achieve Least-Cost Utility Strategies", presented at the mid-year meeting of the National Association of State Utility Consumer Advocates, June 1987.

____________, "Balancing Different Economic Perspectives in Demand-Side Resource Evaluation", Presented at New York State Workshops on Demand-Side Bidding, Albany, NY, March 1988.

____________, "Pursuing Least-Cost Strategies for Ratepayers While Promoting Competitive Success For Utilities", Komanoff Energy Associates, presented at the National Association of Regulatory Utility Commissioners Least-Cost Planning Conference, Aspen, CO, April 16, 1988.

Ruff, L.E., "The Basic Economics of Utility Least-Cost Supply Planning and Demand Management," Putnam, Hayes and Bartlett for Northeast Utilities, October 1987.

Ruff, L.E., "Least-Cost Planning: Five Common Fallacies and One Simple Truth"xx, Public Utilities Fortnightly, xx 1988.

Smith, xx, Testimony on behalf of District of Columbia Natural Gas, DCPSC 834, Phase II, xx 1987.

U.S. Department of Energy, "Energy Security: A Report to the President", March 1987.

Train, K., "Discount Rates in Consumers' Energy-Related Decisions: A Review of the Literature", Energy 10(12): 1243-1253, 1985.

Wisconsin Public Service Commission, Findings of Fact, Conclusion of Law and Order, in Docket 05-EP-4, 5 August 1986

APPENDIX E:

CORRECTION OF META SYSTEMS ESTIMATE OF CONSERVATION BENEFITS

Appendix E: Correction of Meta Systems Estimate of Conservation Benefits

	BASE			DELAY			META SYSTEMS SAVINGS ESTIMATE			Avoided Cost due to Conservation		Other 6.5 month Demand Charges	Total Value of conserve
	Sendout (BCF) [1]	Ave cost ($/MMBTU) [2]	Total ($M) [3]	Sendout (BCF) [4]	Ave cost ($/MMBTU) [5]	Total ($M) [6]	Sendout (BCF) [7]	Ave cost ($/MMBTU) [8]	Total ($M) [9]	Savings ($M) [10]	$/MMBTU [11]	($M) [12]	($/MMBTU) [13]
1991	51.4	4.768	245.1	51.3	4.765	244.4	0.1	0.003	0.154	0.631	6.31		6.31
1992	52.3	5.162	270.0	52.0	5.158	268.2	0.3	0.004	0.208	1.757	5.86		5.86
1993	53.1	5.562	295.3	52.7	5.557	292.9	0.4	0.005	0.264	2.488	6.22		6.22
1994	54.0	5.964	322.1	53.4	5.956	318.1	0.6	0.008	0.427	4.006	6.68		6.68
1995	54.8	6.390	350.2	54.1	6.364	344.3	0.7	0.026	1.407	5.880	8.40	3.72	13.72
1996	55.6	7.009	389.7	54.8	6.994	383.3	0.8	0.015	0.822	6.429	8.04	3.87	12.88
1997	56.4	7.642	431.0	55.6	7.626	424.0	0.8	0.016	0.890	7.003	8.75	4.03	13.79
1998	57.3	8.283	474.6	56.4	8.258	465.8	0.9	0.025	1.410	8.865	9.85	4.19	14.50
1999	58.1	8.930	518.8	57.3	8.903	510.1	0.8	0.027	1.547	8.691	10.86	4.35	16.31
2000	59.0	9.581	565.3	58.1	9.55	554.9	0.9	0.031	1.801	10.424	11.58	4.53	16.61
2001	59.8	10.081	602.8	59.0	10.064	593.8	0.8	0.017	1.003	9.068	11.33	4.71	17.22
2002	60.6	10.596	642.1	59.8	10.567	631.9	0.8	0.029	1.734	10.211	12.76	4.90	18.89
2003	61.4	11.114	682.4	60.6	11.084	671.7	0.8	0.030	1.818	10.709	13.39	5.09	19.75
2004	62.3	11.637	725.0	61.4	11.606	712.6	0.9	0.031	1.903	12.377	13.75	5.30	19.64
2005	63.1	12.164	767.5	62.3	12.129	755.6	0.8	0.035	2.181	11.912	14.89	5.51	21.78
Present Value (1987) @ 14%							2.40		3.496	22.402		9.46	
Levelized Savings ($/MMBTU)								1.46			9.34		13.29

Notes:

1,2,4,5: From Meta Systems Study, Exhibit 4-3.
3: [1]*[2]
6: [4]*[5]
7,8: From Meta Systems Study, Exhibit 4-3.
9: [4]*[8], identical to Meta Systems results.
10: [3]-[6]
11: [10]/[7]
12: $5 million/year in 1987$, times 6.5/12 months not counted, plus 4% inflation.
13: ([10]+[12])/[7]

Levelized Savings equals present value of corresponding total savings, divided by the present value of sendout reduction.