COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF PUBLIC UTILITIES

Re: D.P.U. 20055

TESTIMONY OF PAUL L. CHERNICK ON BEHALF OF THE ATTORNEY GENERAL

FRANCIS X. BELLOTTI
ATTORNEY GENERAL

By: James C. McManus
Assistant Attorney General
Utilities Division
Public Protection Bureau
One Ashburton Place, 19th Floor
Boston, Massachusetts 02108
(617) 727-4885

January 23, 1980

TABLE OF CONTENTS

I. INTRODUCTION AND STATEMENT OF QUALIFICATIONS

Q: Mr. Chernick, would you please state your name, position, and office address.

A: My name is Paul Chernick. I am employed by the Attorney General as a Utility Rate Analyst. My office is at One Ashburton Place, 19th Floor, Boston, Massachusetts 02108.

Q: Please describe briefly your professional education and experience.

A: I received a S.B. degree from the Massachusetts Institute of Technology in June, 1974, in Civil Engineering and a S.M. degree from the same school in February, 1978 in Technology and Policy. I have been elected to membership in the civil engineering honorary society Chi Epsilon, to membership in the engineering honorary society Tau Peta Pi, and to associate membership in the research honorary society Sigma Xi. I am the author of <u>Optimal Pricing for Peak Loads and Joint Production: Theory and Applications to Diverse Conditions</u>, Report 77-1, Technology and Policy Program, Massachusetts Institute of Technology. During my graduate education, I was the teaching assistant for courses in systems analysis. I have served as a consultant to the National Consumer Law Center for two projects: teaching part of a short course in rate design and time-of-use rates, and assisting in preparation for an electric time-of-use rate design case.

Q: Have you testified previously as an expert witness?

A: Yes. I have testified jointly with Susan Geller before the Massachusetts Energy Facilities Siting Council and the Massachusetts Department of Public Utilities in the joint proceeding concerning Boston Edison's forecast,. docketed by the E.F.S.C. as 78-12 and by the D.P.U. 19494, Phase I. I have also testified jointly with Susan Geller in Phase II of D.P.U. 19494, concerning the forecasts of nine New England utilities and NEPOOL, and jointly with Susan Finger in Phase II of D.P.U. 19494, concerning Boston Edison's relationship to NEPOOL. I also testified before the E.F.S.C. in proceeding 78-17, on Northeast Utilities Associates' forecast, and joingly with Susan Geller before the Atomic Safety and Licensing Board in Boston Edison Co., et. al, Pilgrim Nuclear Generating Station, Unit No. 2, Docket No. 50-471 concerning the "need for power". I have also submitted prefiled joint testimony with Ms. Geller in the Boston Edison time-of-use rate design case, D.P.U. 19845, but we have not yet testified.

Q: Do you have any other introductory remarks?

A: Yes. The preparation of this testimony was facilitated by the computational assistance of Michaela Cleary and Adam Frieman, and especially by the production skills of Joan Cassell.

II. EASTERN UTILITIES ASSOCIATES FORECAST

Q: What portions of the EUA forecast methodology will you discuss?

A: We will describe problems in EUA's projections of residential household size, saturation and penetration rates, average energy use per appliance, average base use, and energy consumption by New Developments; its estimates of commercial and industrial sales; and EUA's treatment of wholesale demand contracts.

Q: Are EUA's household size projections reasonable?

A: No. The projection for Brockton does not appear to be based on any methodology at all, and those for Fall River and Blackstone include archaic data which are not representative of recent trends. The data given in the response to IR AG-M-1 indicates that, following World War II, the People/Customer Ratio (which is essentially a measure of household size) fell dramatically in each company for a period of years. At some point, however, these rapid declines stopped; this change occurred in 1956 for Brockton, in 1960 for Fall River and in 1966 for Blackstone. Thereafter, the data starts to meander up and down, with only slight overall downward trends for Fall River and Blackstone; Brockton household size actually rose fairly steadily from 1956 until 1969, when it started to demonstrate the same behavior as the data for the other companies. Inclusion of this earlier data will exaggerate the real recent rate of decrease in family size (except for Brockton, where the 1956-1969 data would understate the recent decrease or even predict increases).

EUA does not seem to have any reasonable justification for including changes in family size (stemming from changes in demographic factors, economic conditions, and life-styles) which occurred in the 1940's, 1950's, and even the early 1960's in projections for the 1980's. Clearly, the changes which occurred in that period are unlikely to recur in the near future; more likely, the 1980's will resemble the 1970's, perhaps the later 1960's.

Accordingly, we have repeated EUA's projection methodology for household size, using only the data for each company for which the trends are reasonably consistent. For Fall River and Blackstone, we have excluded the data from the early years of rapid decline in family size; for Brockton, we have also excluded the period of rising family size. We have used all other aspects of EUA's methodology, including the functional form, the method of correcting the prediction to fit a short-term projection, and even EUA's projection for 1979 and 1980. Our results are presented in Table 1.

Dividing these household sizes into the 1988 population from p. II-5 of Exh. M-10 gives 1988 customer numbers of 69,571 for Blackstone, 99,233 for Brockton, and 46,081 for Fall River; these are respectively 1008, 3355, and 348 lower than EUA's projections. The total difference of 4,711 customers is 21.7% of the customer growth EUA projects for 1978-1988.

The bulk of the difference in customer projections is due to Brockton, for which EUA's projection is entirely subjective. Unlike EUA's other projections, or our projections, which decrease more slowly over time, the decline in EUA's Brockton household size projection increases over time, generating most of its excess households in the late 1980's. This difference can be observed by comparing the first row of Table R-2A (Exh. M-10) with corresponding rows of Tables R-1A and R-3A. In essence, EUA has projected that these excess and unjustified customers will come on line when the projected penetrations are highest. Therefore, these excess customers are projected to use much more electricity than the average customer. EUA has not only inflated the 1988 customer number, but has also artificially inflated the average use of the excess customers.

Company	Time Period	Estimated Co-efficients(1) (a)	(b)	Predicted Family Size 1979/80(3)	1988
Blackstone	1966-1980	0.32951	- .5296	3.0971	3.091
corrected(2)			- .3485	3.0755	3.071
Brockton	1969-1980	0.29547	- .3236	3.4314	3.347
corrected			- .3479	3.4350	3.430
Fall River	1960-1979	0.33086	-1.4230	3.1964	3.177
corrected			-1.1831	3.1657	3.150

Table 1: Family Size Trends, Using EUA Methodology, But Omitting Data For Early Period Of Rapid Decline.

(1) in Ratio = $\frac{\text{Year}}{a\ (\text{Year}) + b}$

(2) with b adjusted so that predicted ratio = short term projection for last data year

(3) last data year

Q: How does EUA forecast changes in appliance saturations?

A: EUA generates future appliance saturations by applying penetration rates to new customers in each year, and by assuming various levels of conversions from other energy sources and of new appliance acquisition by existing customers. The specific assumptions are detailed on pp. II-11 through II-19 of Exh. M-10, and in the response to the Attorney General's Information Request 76 to Montaup.

What EUA does not explain, and apparently cannot explain, is how these penetration and saturation components were predicted. In particular, EUA cannot justify the enormous increases in penetration rates between the short-term (1979, 1980) and the long-term (1988). For example, water heating penetration is assumed to increase 463% in nine years for Blackstone, 317% for Brockton, and 454% for Fall River; while space heating penetrations for the companies are assumed to increase 529%, 560% and 500%. Other appliance penetrations are implicitly set equal to current saturations in 1979; they generally increase considerably in 1980 and then increase consistently out to 1988. Conversion rates (and saturation increases) are zero for all appliances in 1979, and continue to be zero through 1981 for hot water and 1984 for space heat. Starting in 1980 (1982 for water heating, 1985 for space heating), customers are assumed to suddenly start switching from gas and oil to electricity, and to suddenly start buying more dryers and freezers and air conditioners. For ranges, hot water and space heating, conversion rates accelerate continuously until 1988, increasing by 800%, 2500%, and 550% respectively.

The impact of these increased rates of saturation and penetration is considerable. Table 2 presents the number of excess appliances and the number of extra MWH due to each of the appliances for each company. This Table simply presents the difference in customer number with each appliance due to the forecast increase in penetration to new customers, due to the conversion rate increases (space heating, water heating, and range), and due to accelerated saturation increases in frost-free refrigerators (partly offset by reductions in saturation increases for standard refrigerators). The base year in each case is 1980, except for space and water heating, for which EUA made explicit assumptions for 1979.

From Table 2, a total of 81763 MWH is due to the increases in penetration and saturation parameters between 1979/80 and 1988. This is 5.2% of total residential use in 1988, and is entirely unjustified.

Appliance	Blackstone Valley	Brockton	Fall River
Spaceheat			
new:	277	2,040	104
existing:	223	308	146
average use:	10,534	10,310	9,723
MWH:	5,267	24,208	2,431
Water heat			
new:	555	2,959	199
existing:	2,556	2,462	1,716
average use:	4,004	4,202	3,920
MWH:	12,456	22,779	7,507
Range			
new:	182	604	88
existing:	1,328	1,110	961
average use:	1,164	1,164	1,164
MWH:	1,758	1,995	1,221
Dryer			
new:	82	0	40
average use:	960	960	960
MWH:	79	0	38
A/C			
new:	80	773	14
average use:	1,350	1,350	1,350
MWH:	108	1,044	19
F/F Refrigerator			
new:	204	903	94
existing:	124	175	83
average use:	1,105	1,105	1,105
MWH:	362	1,191	196
Standard Refrigerator			
new:	-131	-597	-61
existing:	-124	-175	-83
average use:	765	765	765
MWH:	-195	-591	-110
Totals MWH	19,835	50,626	11,302

Table 2: Appliance Units and KWH Due to Increases in Saturation and Penetration Parameters.

Q: Does EUA make any attempt to justify its projection of increasing penetration of electric appliances?

A: Yes. EUA claims that electricity will become "more desirable" as an energy source as fossil fuel prices rise. There are three flaws with this argument. First, it provides no justification for increasing saturations of air conditioners, freezers, refrigerators, or frost-free refrigerators. In fact, the rapid increases in oil and gas prices Mr. Gmeiner seems to expect would not leave much disposable income for purchases of these luxuries - if anything, this argument would predict falling saturation of these appliances, falling base use, and little or no New Developments.

Second, EUA provides no forecast of electric, gas and oil prices. As we demonstrate in Section V below, the nuclear capacity which EUA would like to add is likely to substantially increase its retail rates. EUA's statements that electricity prices will rise more slowly than fossil fuel prices appears to rest entirely on Mr. Gmeiner's unsubstantiated judgement.

Third, in a system for which oil is generally the marginal fuel, no rationally designed electric rate can produce electric costs lower than oil costs for space and water heating. Mr. Gmeiner has testified (Tr. IX-77) that EUA's marginal heat rate ranges from 9650 to 15000 BTU/kwh, or 23% to 35% efficiency. These generator-level efficiencies must be modified for marginal line losses; for example, for Boston Edison residential customers, we found that these losses averaged 22.5% (D.P.U. 19845, testimony of Chernick and Geller), while Massachusetts Electric's average estimate of its residential marginal losses is about 22.7%. These transmission/distribution marginal efficiences are about 82%. Therefore, the efficiency at which EUA is likely to deliver energy from oil to its customers is around 19% to 29%. According to DOE figures, customers can burn oil directly for water heating at 50% efficiency and for home heating at 82% efficiency for forced air systems and 85% for hot water systems. Even with the current price differential of 40% between high-sulphur #6 and #2 oil, EUA's most efficient units can barely compete with water heating, the less efficient direct use of oil. (The lower efficiency units burn #2 oil.) Of course, if natural gas continues to be cheaper than oil, electricity will be even less competitive against gas.

Q: What errors does EUA make in projecting average energy use per appliance?

A: EUA makes four kinds of errors in assuming that:

a. existing DOE appliance efficiency standards will not be met,

b. new tougher appliance efficiency standards will not be imposed before 1988,

c. historic declines in hot water and space heating usage will not continue, and

d. decreasing family size will not affect average usage.

Q: What justification does EUA advance for assuming that existing DOE standards will not be met?

A: EUA offers two excuses for failing to utilize the full DOE efficiency improvements. The first is that the standards to which EUA was referring were targets, which were not yet mandatory. This is a somewhat disingenuous response. On January 2, 1979 (five months before Exh. M-10 was filed at the EFSC) DOE published proposed mandatory efficiency rules in the Federal Register, which indicated that the initial mandatory rules will become effective in June, 1981.

The second justification rests on the statement that "the rulings are based on 1972 uses whereas EUA's average uses are more current, reflecting some efficiency improvement" (IRM-4). EUA has presented no evidence that the 1972 averages are really higher than their 1980 usages, and for good reason: EUA does not in fact believe that there has been any improvement in appliance efficiency since 1972. This is readily apparent in two ways. First, the responses to IRM-3, IRM-61 and IRM-67, as well as the R-Tables in Exh. M-10, indicate that EUA believes that energy consumption per appliance has been constant since 1960, including 1970, 1975, 1976, 1978, 1979, and 1980 (water heater use varies up to 1978, but is then constant through 1980). Obviously, if the average usage for new appliances changed any time in this period, the average of all appliances would also have changed; Tables R-1C, R-2C, and R-3C in Exh. M-10 show this effect in 1981, the first year in which EUA projects improved efficiency. The second indication that EUA does not believe that appliance efficiencies have changed substantially is that average use by new appliances (e.g., Table R-1A) is assumed to equal average use by all appliances (e.g., Table R-1C) in 1978 through 1980, for each appliance type. Again, if new appliances had become more efficient in the 1972-80 period, then the 1980 average use by the stock of appliances would exceed that of new appliances, conversions to the somewhat higher efficiencies would start in 1979 (not 1981), and the impact on sales of each conversion would be larger than the difference between 1980 and 1981 average use by new appliances. The latter two effects would tend to produce a lower forecast than EUA's assumptions do. The fact that water heating average use is the same for new and existing customers in 1980 indicates that EUA attributes reductions from earlier levels to behavioral changes, weather variations, and end use efficiency improvements (pipe insulation, flow reducing showerheads, etc.), rather than to any change in water heater efficiency.

Q: Does EUA offer any evidence that appliance efficiencies have improved since 1972?

A: No. However, EUA does quote from the Federal Register to the effect that 29.2% of the refrigerator models available in 1977 exceeded the 1980 target. It is still perfectly possible that the average of refrigerator model efficiency is no higher than the 1972 level, depending on the efficiencies of the other 70.8% of models. In addition, the standard is for production-weighted efficiency; the very efficient units may have lower sales than the very inefficient ones. Therefore, the statement EUA quoted does not really say anything useful, except that exceeding the standards is clearly technically feasible.

Q: What indication is there that appliance efficiency standards stricter than the current DOE standards will be imposed by 1988?

A: Table 3 lists the 1972 average new-appliance efficiencies, the current 1980 efficiency targets, and the new preliminary DOE mandatory standards. The new standards are minimum levels, rather than sales-weighted averages, so they are inherently stricter than the old targets, even at the same numerical level. In addition, the new proposed standards are generally higher (more stringent) than the existing standards; in some cases (e.g., refrigerators, central air conditioners, televisions), the improvements are considerable. Since these standards are all based on appliances currently on the market, it is evident that they are technically feasible.

Appliance	1972 (1)	Old 1980 Targets (1)	New Preliminary Standards (2)
Std. Frig. F/F Frig.	3.8	5.28	10.1-10.4 cu. ft./kwh-day 6.6 cu. ft./kwh-day
Freezers	7.47	9.57	9.1 - 16.9 cu. ft./kwh-day
Dryers	2.64	2.75	2.61 - 2.77 lb./kwh
Waterheaters	.80	.94	.89 EF
Room A/C	6.2	7.94	7.5 - 11.6 BTU/wh (EER)
Range:			
top	.7484	.7484	.79 EF
oven	.1299	.1353	.14 - .16 EF
Central A/C			
split	6.6	8.1	10.3 SEER
single	6.2	7.2	8.9 SEER
Clothes Washer	.65	.88	1.01 - 1.25 cu. ft./kwh
D/W	.241	.301	.41 - .50 cycles/kwh
TV: B/W	35	100	176% REEF
color	65	100	229% REEF
Dehumidifiers	1.965	2.338	2.9 pints/kwh

Table 3: Comparison of Old and New DOE Efficiency Standards

(1) from Federal Register (FEDREG) 4/11/78, 10/12/78
(2) from FEDREG 1/2/79, 12/13/79

Q: Please explain why it would be appropriate for EUA to project decreasing average use for space heating and water heating.

A: As Table 4 shows, EUA's own estimates indicate that average energy use for space heating has fallen steadily since 1975, measured either as kwh/year or as kwh per heating degree day (HDD). Nonetheless, EUA projects that space heating usage will increase in 1979, by 2.4% to 7.5%, compared to 1978 weather-adjusted consumption, and remain constant thereafter. The 1978-79 increase is projected to be greatest in Brockton, where EUA expects to add the vast majority of its new electric heating customers, and lowest in Fall River, where very few new heating customers are expected, so the system-wide increase is weighted towards the higher increase.

Since EUA's own data shows space heating average use to be falling in the post-embargo period, and since the only explanation EUA can offer for the source of its space heating average use projection is that it is "based on 1978 rate/revenue company data", the increase in 1979 is inexplicable. It is also difficult to understand why the dramatic decline in space heating energy consumption (36% in 3 years for Brockton, weather adjusted) is expected to stop abruptly. The decline in energy use may have partially resulted from construction of smaller, better weather-proofed homes. However, since the total energy use by electric heating customers has declined since 1976, even while the number of electric heating customers has increased (and winters have grown colder), it is clear that existing customers have also reduced their use, through behavioral changes (e.g., temperature settings, drape openings) and retrofitting of insulation, other weather-proofing measures and wood stoves. As the price of electricity increases, the efficient level of weatherization also increases; it is unlikely that EUA's heating customers (either existing or new) have suddenly run into either technical or economic limits to space heating conservation measures.

A similar situation prevails for water heating; EUA reports large decreases in average use from 1976 to 1978, but only modest appliance efficiency improvements in the future. It is unlikely that EUA's customers have completed the process of insulating water tanks and pipes (and the basement and wall spaces around them), of installing flow-reducing devices on showers and faucets, of lowering water temperatures, and of adapting behavior to reduce hot water use. The effect on hot water use of mandatory efficiency improvements in clothes washers and dishwashers has not yet been felt at all; this effect will be substantial, although the quantitative magnitude can not be determined without estimates of saturations of those water-using appliances.

Extrapolating the 1976-78 decline in spaceheating and water-heating use to 1988 decreases sales by about 220 GWH.

Year	Blackstone		Brockton		Fall River	
	space heat kwh)	water heat (kwh)	space heat (kwh)	water heat (kwh)	space heat (kwh)	water heat (kwh)
1975(1)	12,500	5,700	14,000	5,700	13,000	5,700
kwh/HDD	2.09		2.27		2.33	
1976(1)	12,255	5,737	11,845	6,093	11,754	5,700
kwh/HDD	1.89		1.74		1.92	
1978(2)	10,535	4,449	10,310	4,669	10,022	4,356
kwh/HDD	1.59		1.46		1.60	
1978 kwh average HDD	10,083		9,590		9,994	
1988 kwh(3)	4,249	1,248	3,989	1,234	4,016	1,135
EUA Forecast	10,534	4,449	10,310	4,669	9,723	4,356

Table 4: Comparison of EUA Estimates for Average Space Heating and Water Heating Use Since 1975

(1) from p. 7, Exh. M-14
(2) water heat from IRM-3
space heat calculated from IRM-3 and Table E-1, Exh. M-10
(3) 1976-78 compound growth, extrapolated to 1988, with average HDD

Q: What effects does family size have on energy use per appliance?

A: Clearly, if there are fewer people per household, then the average home will be occupied (and hence heated or cooled) for fewer hours, fewer rooms will be used (and hence heated, cooled and lit) at any one time; the home will tend to be smaller; fewer showers will be taken; fewer dishwasher, dryer, and clothes washer loads will be run; the refrigerator and freezer will tend to be smaller; and the televisions will be fewer and operated fewer hours. This relationship has been quantified by NEPOOL, BECO, EPRI, and the TVA.

Boston Edison's Appliance Utilization Study (Final Report 1978) indicates that saturations of TV's (both black and white and color) ~~and bed warmers (such as electric blankets)~~ and the number of light bulbs in a home, all vary significantly with family size, and that smaller households are more likely to engage in conservation efforts.

The NEPOOL-Battelle forecasting model documentation (Report on A Model for Long Range Forecasting of Electric Energy and Demand, June 30, 1977, p. G-23) reports that a reduction in household size of one person per household will decrease range use 12.3%, refrigerator use 7.5%, dryer use 16.6%, and hot water use 16.6%.

An EPRI report (Patterns of Energy Use by Electrical

Appliances, EPRI EA-682, January, 1979, prepared by Midwest Research Institute) reports similar sensitivities; one fewer person in an average household reduces use by 9.7% for ranges, 30% for clothes washers, 23% for dryers, and 15.3% for water heaters.

A TVA study (reported in How Electric Utilities Forecast, EPRI EA-1035-SR, March, 1979, p. 4-15) found that removing one child from the average EUA-size household (3.3 persons) reduces total electrical use by 16.1%. 1.35%

other collinear factors -working women

Q: Please explain how EUA's Base Use projection is in error.

A: Basically, the derivation of Base Use growth is dependent on assumptions which are inconsistent with the forecast assumptions. For each of the 1975, 1976, and 1978 Base Use calculations presented in Exh. M-14 and in information response M-3, the saturations of most appliances are held constant, despite the fact that these saturations are all forecast to increase in every future year. Space-heating use and water-heating use is reported to have decreased substantially over the same period, even though no corresponding decreases are forecast.

Under these circumstances, it is not surprising that EUA can "demonstrate" increases in Base Use. All real saturation increases, and any overestimates in the dramatic decreases in space and water heating average use are reflected in EUA's Base Use, in addition to the lighting and small appliances it is intended to represent, and the general conservation trend which it inherently captures (since most appliances' average use values are held constant).

In Table 5, we calculate 1975, 1976, and 1978 Base Use (1) on the basis of assumptions consistent with values forecast by EUA for 1979 and 1980, and (2) on the basis of the same assumptions, but with EUA's annual space and water heating average use assumptions. On a basis entirely consistent with the forecast, the annual Base Use growth rate was -39.2% 1975-76, -51.2% 1976-78, and -47.7% 1975-78. The corresponding growth rates using EUA's figures for space and water heating are 4.3%, 3.7%, and 3.9%. Clearly, it is critical that the Base Use projection be based on reliable data which is consistent with forecast assumptions. Since a consistent analysis yields strong negative Base Use growth, and an analysis (p. 10, Exh. M-14) based on actual 1970 census saturations produces negligible growth, it is evident that EUA's highly subjective and inconsistent growth rates for Base Use (4.9% for Brockton, including Unforeseen Appliances) have no basis in the historical record.

EUA presumably realized that the Base Use forecast was implausible, since it is reduced in 1979 and 1980 to negligible levels (e.g., 0.22% for Brockton). If 1978 Base Use per household is held constant for each company, EUA residential sales are reduced by 114,766 KWH in 1988. ← ?

Year	Annual %/kwh Increase	1975	1976	1978
Heating Degree Days		6,166	6,806	7,042
EUA heating estimate		14,000	11,845	10,310
EUA water heat estimate		5,700	6,093	4,669
Normalized heating (1)		9,706	10,713	11,084
Forecast water heat		4,669	4,669	4,669
Range		1,164	1,164	1,164
Dryer (2)	.66/6.6	750	757	770
Freezer (2)	.61/8.54	350	359	376
A/C (2)	.84/12.6	375	388	413
Refrigerator (3)	-/8.33	1,342	1,350	1,367
Total: normalized		18,356	19,400	19,843
Total: EUA		23,681	21,956	19,069
Base Use: normalized		6,894	4,193	985
Base Use: EUA		1,569	1,637	1,759

Table 5: Brockton Base Use Estimates

(1) $\frac{10310}{6550}$ x HDD

(2) assumes 1975 value correct, increases at 1979-80 rate
(3) assumes 1979 value correct, increases at 1979-80 rate

Q: Are there any reasons to expect Base Use growth to be lower in the future than it was in the past?

A: Yes. Certain appliances in the Base Use category, (televisions, humidifiers, clothes washers, dishwashers, dehumidifiers) will be covered by DOE efficiency standards. As EUA recognizes (IRM-7), television manufacturers are already ahead of DOE's original voluntary standards; as older TV's are replaced, energy consumption by this appliance will fall. It is certainly reasonable to assume that the conservation in large and small appliances, in lighting, in hot water use, and/or through insulation (which saves on air conditioning energy as well), which we have documented in the normalized Base Use growth, can be expected to continue.

Q: Is EUA's inclusion of "New Developments" in the residential forecast reasonable and justified?

A: No. This portion of the forecast is conceptually muddled and completely without relevant analytical support. The errors in EUA's argument for including "New Developments" can be summarized as follows:

1. confusion in concepts and terminology,
2. failure to recognize overlap with Base Use and other appliances, and
3. confusion regarding the nature of technical change and progress.

Q: Please explain how EUA's description of "New Developments" reveals a confusion in concepts and terminology.

A: EUA's forecasters have consistently maintained, when speaking in generalities, that "New Developments" or "Unforeseen Appliances" are large energy-using appliances, and that small appliances are modelled as Base Use (EFSC 78-33, Tr. pp. 34,36). However, the specific examples of "New Developments" are generally small kwh uses, such as calculators, shaving cream dispensers, and electric corn poppers (IR 73, 74). The only major "New Development" EUA appears to be able to imagine is the electric car, which was the original model for an Unforeseen Appliance in EUA's 1976 forecast. Despite the intervening 3-1/2 years, EUA has yet to demonstrate that this one candidate appliance has any reasonable chance of becoming economically competitive with vehicles of similar performance characteristics, running on liquid (or even gaseous) fuels. EUA has not even indicated that electric cars would use less oil than equivalent gasoline-fueled automobiles. If the electric car fails to become commercially viable, EUA has no other possible "Unforeseen Appliances", since the rest of their list (Exh. M-14, p. 11) consists of appliances which, on the basis of size, fit into the Base Use definition.

In addition, EUA cannot seem to decide whether "New Developments" have to be new. For example, Mr. Gmeiner's six possibilities (Exh. M-14, p. 11) include three (food processors, video tape recorders, and video disc players, plus increased TV use with the video devices) which EUA counts as historical examples of New Developments, which contributed to 1978 demand (IR73, 74). Even Mr. Gmeiner has admitted that, once an appliance has been introduced commercially, it is no longer an Unforeseen Appliance (EFSC 78-33, Tr. p. 45). EUA would like to distinguish between new and existing uses for the purpose of justifying a New Development category, and then to ignore the distinction so that existing uses can be listed as new.

Q: How does EUA fail to differentiate "New Developments" from Base Use and other appliances?

A: As EUA admits, the historical figures for Base Use growth include New Developments (Exh. M-14, p. 10; Dep., p. 40). Therefore, a reasonable Base Use forecast will include New Developments, to the extent they are included in the historical data. In IR73/74, EUA lists some of the New Developments which are counted in the essentially flat base use growth from 1970-78; similar developments are therefore assumed in an extrapolation of that base use growth. The inclusion of a separate New Developments category double-counts these appliances, and implicitly assumes a sudden surge of new electric uses in the middle to late 1980's.

Q: Please describe EUA's confusion regarding the nature of technical change and progress.

A: Mr. Gmeiner apparently believes that social progress and electricity use are inextricably linked, and that "[t]here will be more [electric uses] in the future unless society dries up." (EFSC 78-33 Tr. p. 22). Not only has EUA never demonstrated such a linkage, but many of their own analyses dispute it.

For example, Mr. Gmeiner's entire historical argument for the inclusion of New Developments is based on the period 1946 - 1960 (Exh. M-14, pp. 11-13). Yet EUA admits (IR 73/74) that the 1946-69 product developments were radically different from those which have occurred since. While the early period saw the introduction of some large new uses (TVs, air conditioners, dryers, freezers, and dishwashers) and many small new uses, the 1970's have been notable for appliances which replace other electric uses (such as microwave ovens, automatic coffeemakers, food processors, and electric corn poppers) and those with only intermittent use (garage door openers, electric chain saws, trash compactors). Therefore, extrapolation of future New Developments from the pre-1970 period is highly problematical.

Indeed, the factors which drive product development and adoption have changed considerably since 1946, and even since 1970. First, the price of electricity has stopped falling, and has started rising. As a result, energy-conserving products (e.g., systems that recover refrigerator or air conditioner waste heat for domestic hot water, the Nola Power Factor Controller, and more efficient lighting systems) will tend to dominate energy-consuming uses (e.g., instant-on TVs). Second, there are many electricity-using devices in homes today, while there were few in 1946. In 1946, more efficient cooking devices could displace range oil, but not electricity; today, a sizeable portion of displaced energy would be electric. Third, even before the effects of recent price increases on research and development efforts, technical progress was leading to more efficient energy uses, particularly in solid state electronics and microwave ovens. These three changes (price trends, electric saturation, and technical progress) are unlikely to stop or reverse in the 1980's; use of historic New Development trends, even from the 1970's, may well overstate future contributions in this category. Therefore, the 1970-78 Base Use trends include a generous, and perhaps excessive, allowance for New Developments.

Q: Do you have any comments on EUA's commercial forecast?

A: Yes. Basically, the methodology makes very little sense. The number of commercial customers is simply not a useful predictor of commercial use, EUA's data and projections are highly subjective, and the regressions tested and selected are frequently inappropriate.

Q: What problems arise with using customer number in the commercial forecast?

A: A single commercial customer can be a law office with 2 employees or a corporate headquarters with 2000 employees, a tiny trailor shop or a massive shopping center. Unlike the residential customer/household, the commercial customer is not a natural unit. In addition to wide variation in electric intensity due to choices similar to those facing residential customers (e.g., choice of energy type, conservation consciousness), commercial electric use can vary widely due to business type and size.

Q: In what ways are EUA's data and projections subjective?

A: Since historical data did not accurately or consistently count actual commercial establishments, EUA had to estimate the magnitude of the error in each previous year. The same is apparently true for population data, which was interpolated or extrapolated.

In no case did EUA actually use the projection generated by the selected regression. In one case, EUA makes a simple level adjustment (a common technique, although not necessarily preferable to a proportional adjustment) to reconcile the projection with "actual" data (really another projection). In other cases, one end of the 99% confidence interval is used as the projection. This is a very odd procedure, since the bound of the 99% confidence interval is, by definition, the curve which has only a 0.5% chance of having produced data as extreme as the observed (or estimated, in EUA's case) data.

Q: How are EUA's regressions inappropriate?

A: For each service territory average use per commercial customer is projected as a linear function of population and of the residential/commercial customer ratio. The latter term makes sense; combined in a multiplicative equation with household size and electric price, it would be perfectly reasonable. However, total population has no logical connection with average commercial use, although population per commercial customer might. Population appears to be a rough surrogate for time; indeed, average use increased fairly steadily over time (due to larger customer size, as well as real increases in electric use) until 1973. The 1976-78 average use growth rates are less than a third of the pre-1970 growth rates for each company; for Brockton, growth has fallen from 10.7% 1960-73, to .7% 1976-78. EUA's equation has no mechanism to explain this change.

Both population and household size seem to be reasonable explanatory variables in a multiplicative model of commercial activity; unfortunately, EUA chose to use them in a linear model of commercial customer number, which is not itself a very good measure of commercial activity, as noted above. Even if EUA did not initially realize that the equation was inappropriate, one would think that finding a positive coefficient for household size in Blackstone, a negative sign in Brockton, and no acceptable equation in Fall River (although EUA certainly did not look very hard for the latter) would alert the forecasters to the existence of a problem. Apparently, they did not notice that bigger families were increasing economic activity in one service territory while suppressing it in another; or perhaps they did not care whether the model structure or coefficients made sense, so long as the projections fit their expectations. There is no evidence of any reasoned approach to modeling these relationships, either in determining which models to run, or in selecting the appropriate specification from among the alternatives.

Q: What errors does EUA make in its industrial forecast?

A: The most serious error is the omission of certain data from the projections used in the forecast. EUA omits all sales to certain large customers which left the service territory in the middle 1970's, and ignores the result of the

Brockton regression for small customers, with the claim that, again, certain industries had left the service territory. In essence, EUA assumes that, while some of their industrial customers had failed or left the service territory in the recent past, the same phenomena will not be observed in the future, but that new customers will continue to arrive at historic rates, and that sales to all customers will grow at the same rate as the successful firms of the 1970's. Indeed, EUA specifically projects an expansion of one large customer in Blackstone, in addition to the general growth rate. Special decreases in sales are restricted to the past, and special increases to the future in EUA's view. Including all sales data would decrease historic growth rates, actually making the growth rate negative for large Fall River customers, and reducing Brockton's growth rate to 0.6%.

For most of the projections, EUA uses (adjusted) 1970-79 growth rates, but only for 1988; from 1980 to 1987, growth rates are subjectively interpolated between the actual 1979 growth rate, and that projected for 1988. Industrial sales growth rates have been very volatile - there is no justification for assuming that short-term growth will approximate 1979 growth. EUA might more reasonably use the 1970-79 average growth rates to approximate the 1979-88 growth rates.

For the Brockton small-customer group, EUA departs from its normal practice. The 1970-79 growth rate was -3.18%; EUA arbitrarily increases the 1979 growth rate of 0.42% up to 0.50% in 1988. In AGIR M-22, the historic decrease in sales was attributed to "the loss of many smaller, shoe-related industrial customers", and was said to thus be "an unreasonable expectation of the future". Indeed, Table E-4, p. IV-3 of Exh. M-10 indicates that sales to the leather and apparel industries have declined since 1970 (although by less than 1970 sales to the two large shoe companies that left). However, so have sales to ten of the other 18 industrial classifications. Brockton's loss of industrial sales has been quite broad-based; attributing the 1970-79 decline to shoes is unreasonable. In any case, the shoe industry has not entirely left, and its exodus may continue.

If the small and large customer groups are consistently projected to 1988, at 1970-79 growth rates, the result is 1988 sales, about 126 GWH lower than the EUA forecast, as is shown in Table 6.

	Blackstone	Brockton	Fall River
1970 large class MWH utilized	173,927	35,730	36,378
1970 actual (total - small class)	173,927	50,868	77,613
1979 value large	192,634	53,488	43,064
Compound growth rate (large)	1.14%	.56%	-6.34%
Compound growth rate (small)	2.16%	-3.19%	5.66%
1988 projected value (large)	230,082	56,184	18,492
1988 projected value (small)	430,412	63,213	168,842
Total EUA 1988 MWH (from IR M-22)	732,969	183,330	217,366
Total consistent 1988 MWH	691,794 (1)	119,397	187,334

Table 6: Consistent Projection of EUA Industrial Sales

(1) includes 31,300 level adjustments for Blackstone

Q: What problems arise in EUA's conversion of sales to peak demand?

A: There appears to be problems in weather adjustment and in projection of load management.

The response to AG IR M-31 indicates that the average temperature at peak was 22° F in Blackstone, 23° in Brockton, and 22° in Fall River, from 1970-78. Using these as average values, instead of 15° F as EUA does, would decrease the weather-adjusted 1978/79 peak by about 13.5 MW. Since the 1978 weather-adjusted load factors are the basis for the peak demand forecast, this 2.2% reduction in peak would carry through the forecast period, reducing 1988 peak by about 19 MW.

EUA has sharply curtailed its estimate of load management effectiveness. In the 1978 forecast, load management was projected to remove 25% of residential heating load, and a like amount of commercial load, from peak. In the 1979 forecast, this value is reduced to 10%. Only new space heating (and only 30% of that) is assumed to be affected; EUA is apparently not concerned enough about peak growth to encourage conversion of existing space heaters, or conversion of existing water heaters to controlled operation, or even promoting (let alone requiring) that new water heaters be controlled. Despite the explicit consideration of TOU rates (affecting all loads) as a load management technique, no non-heating loads were assumed to shift, and no industrial loads were assumed to shift. The latter assumption is perhaps the stranger of the two: TOU rates will almost certainly be widely implemented for industrial customers before they are for residential customers, and preliminary results suggest that TOU rates will have a larger impact on the demand patterns of these large customers.

In addition, EUA continues to forecast a 6 MW Middleboro demand contract which, according to its EFSC filing, Middleboro does not need, does not want, and does not intend to take.

III. FITCHBURG GAS AND ELECTRIC FORECAST

Q: On what aspects of the forecast of Fitchburg Gas and Electric will you comment?

A: We will note three difficulties in the residential forecast, including projection of growth in sales to existing customers, projection of average electric heating energy use, and the allowance for appliance efficiency standards. We will also discuss the industrial forecast.

Q: Did FGE properly estimate the growth in sales to existing non-electric heating customers in 1979?

A: No. The FGE methodology has two major flaws: the growth in new customers from 1978 to 1979 is miscalculated, and the assumption that monthly sales in the first five months are equal to monthly sales over the year appears to be wrong.

Q: Please explain how FGE miscalculated the growth in new customers from 1978 to 1979.

A: The analysis of existing customer sales growth is based in part on figures for the period January to May in 1978 and in 1979. In order to estimate the growth in sales to existing customers, it is necessary to subtract the sales in the 1979 period due to customers who were not on line in 1978. In IR F-41, FGE explains that this calculation was done as follows

use by new customers = 11 x 4000 x 5/12, where 11 is the number of new customers, 4000 is the assumed average annual kwh usage by each new customer, and the fraction normalizes annual use to the five-month period.

Unfortunately, 11 is not the right number of new customers between the 1978 period and the 1979 period; it is the number of new customers who came on line during the 1979 period. The number of new customers between the two periods should be calculated as follows (12/77 customer number is from Table E-2, Exh. FGE-7):

[18602 (in 5/79) + 18591 (in 12/78)] ÷ 2 = 18596.5, average 1/79 to 5/79

[18410 (in 5/78) + 18374 (in 12/77)] ÷ 2 = 18392.0, average 1/78 to 5/78

So the average number of customers between the first five months of 1978 and the first five months of 1979 is 204.5. Plugging this larger and correctly calculated estimate of customer growth into the calculation in IR F-41 gives new customer use in the 1979 period of 340833 kwh, rather than 18333, leaving only 113830 kwh attributable to existing customers, rather than 436,330. This converts to annual growth of 273192 kwh for existing customers, only 27.3% of FGE's forecast.

Q: Please explain how FGE's assumption that monthly energy consumption is constant through the year is in error.

A: FGE simply assumes that electric use in the first five months of a year will be five-twelfths of annual use. This does not appear to be the case. From the data quoted above, and in IR F-41, an average of 18392 non-heating customers used 37058179 kwh in the first five months of 1978, for an average use of 2015 kwh. In the entire year of 197~~8~~9, an average of 18482.5 customers used 85800 MWH, or 4642 kwh each. The ratio of these two average uses is not 5 ÷ 12 = 0.4167, but 0.4341, indicating that customers used more electricity per month in the first five months, than in the year as a whole. This is a reasonable result: the first five months are colder and darker than the year as a whole, and people are less likely to go on long vacations. If 0.4341 is used in the preceding calculations, in place of 5/12, the 1979 period energy due to new customers is 355094 kwh, leaving 99569 kwh for existing customers, or 229369 annually. This is only 22.9% of FGE's forecast growth.

Q: Are the calculations you have presented intended as an estimate of 1979 residential sales to existing customers?

A: Not primarily. Since actual data is now presumably available for 1979, it would be easier and more reliable for FGE to extract sales to existing customers from that data. Unfortunately, we do not yet have year-end customer number and sales, so we cannot yet do this calculation. Our primary purposes were to correct FGE's methodology and to prepare a 1979 sales estimate that was consistent with

FGE's basic assumptions. Of course, these corrections (especially the use of correct new-customer figures) should be embodied in any new estimates FGE produces.

Q: What impact does this correction have on the forecast?

A: Table 7 is ~~a restatement~~ my revision of Exh. FGE-8, Schedule 2, to include the 1979 projection (which results from correcting IR F-41 for existing customer growth and assuming 229.5 new customers, the difference in the 1978 and 1979 average customer numbers, at 4000 kwh each), 1974 data, and more precise total use figures for the non-heating residential class. This table indicates two things; first, FGE's errors in IR F-41 inflated existing customer growth by about 25%, and second, growth has been much slower since 1976 than before.

Year	1974	1975	1976	1979
Customer number(1)	18525	18490	18314	18833
Customer growth to 1979	308	343	519	-----
New customer use 1979, mwh	1232	1372	2076	-----
Total use MWH(1)	81695	82299	84098	86944(2) (87762)(3)
Growth in existing customers' use to 1979 MWH	4017	3273	770	-----
Annual growth, MWH	803	818	257	-----
Annual growth to FGE 1979 forecast	967	1023	529	-----

Table 7: Restatement of Exh. FGE-8, Schedule 2

(1) From Exh. FGE-7, Table E-2
(2) corrected estimate, see text
(3) FGE estimate, Table E-2

The post-1976 value is clearly the more representative base. Since 1976 was the first year of recovery after the oil embargo and recession, growth from 1975 to 1976 was inflated. Also, the 1974 to 1976 period was atypical, in that much older (and presumably low-use) housing was demolished, resulting in negative customer growth. Inclusion of these negative customers tends to understate the real growth in new customers if pre-1976 data is incorporated. Therefore, the 1976 to 1979 trends are preferable to those starting earlier. The sensitivity to starting years is not "marginal", as FGE asserts (IR F-42).

Q: What error did FGE make in forecasting average use by heating customers?

A: Average use has remained remarkably steady over the last few years, despite increasingly cold weather. As Table 8 shows, average use due to space heating (that is, with normal use subtracted out) has fallen considerably on a weather-normalized basis since 1975. Adjusting the 1978 average use for the average number of degree days in the 1970-78 period gives a normalized 1978 use of 8763 kwh, plus 4615 for normal use, for a total of 13377 kwh/customer.

A linear regression of the post-1974 kwh/HDD values in Table 8 predicts a 1988 heating use of 6141 kwh, for a total use of about 10756 kwh/customer, or 26% less than FGE's figure. This difference amounts to 3.6 GWH in 1988.

FGE's projection of a constant use per heating customer is clearly unreasonable.

Year	Heating Degree Days (1)	Average Use Per Heating Customer (2)	Average Non-heating Use (3)	Average Heating Use	Heating Use Per HDD
1970	6281	15100	4035	11065	1.762
1971	6102	15100	4342	10758	1.763
1972	6383	14700	4455	10245	1.605
1973	6166	14600	4613	9987	1.620
1974	6210	14300	4410	9890	1.593
1975	6130	13200	4451	8741	1.427
1976	7039	14600	4592	10008	1.422
1977	7447	14400	4561	9839	1.321
1978	7417	14500	4615	9885	1.33~~1~~3
Average	6575				

Table 8: Trends in Space Heating Energy Use

(1) from IR F-3 and IR F-34
(2) from Exh. FGE-7, Table E-1
(3) from Exh. FGE-7, Table E-2

Q: Did FGE properly incorporate the effects of federal appliance efficiency standards in the residential forecast?

A: No. FGE assumes that only new customers, or existing customers who buy additional appliances, will be affected by efficiency standards. If this were true, FGE's 20% reduction of new customer use and of growth in existing customers would capture a fairly large percentage of the impact, although the effects should be extended to new space heating customers and should be anticipated to start fully by 1981 or 1982, not in 1984, as FGE assumes. However, as EUA realized last year, existing appliances owned by existing customers will wear out and so will also be replaced by improved appliances. This has a substantial effect.

For example, using EUA's assumptions regarding average refrigerator use (900 kwh standard, 1400 kwh frost-free), just a 50% frost-free saturation, a 105% total saturation, a 15 year average life, and a modest reduction of 42% (from the 1972 composite average efficiency to the new frost-free minimum efficiency), we find that the refrigerator stock in 1981 (before standards) will use 24.4 GWH. By 1988, seven-fifteenths of this stock will have been replaced by units of 42% greater efficiency, for a reduction of 4.8 GWH. FGE only reduces 1988 residential sales by 1.21 GWH to account for all appliance efficiency improvements (total

1980-88 "existing customer growth" is set at 7.79, rather than 9.0 GWH in Exh. FGE-8, Schedule 1). Hence, it is clear that FGE is over-forecasting 1988 residential sales by several GWH due to just this one error.

Q: Are there any problems in FGE's industrial forecast?

A: Basically, the central weakness is the absolute subjectivity of crucial projections, but there are some more specific problems, as well.

Of the forecast growth in industrial sales from 1979 to 1988, 71% is due to forecast growth in Industrial Parks and 18% is due to Other Small New Customers (Exh. FGE-10, p. 1). These categories also represent 57% and 14% of total sales growth, 1979 to 1988. Clearly, these two lines of Exh. FGE-10 are the heart of the FGE sales forecast.

FGE's entire explanation of Industrial Park growth can be found in IR F-56. Absolutely no historical data or other sources were used in calculating the rate at which new customers will arrive or the load factor of the customers. FGE claims that "the demand of 500 kw is consistent with current experience", but FGE provides no evidence that four customers of this size are likely to move into the parks each year, or that the parks can accomodate 30 of them.

Even given FGE's assumptions, however, the Industrial Park forecast does not make sense; FGE estimates that the parks can hold 30 customers, each using 2.19 GWH annually, or 65.7 GWH in all. Yet FGE then projects (in Exh. FGE-10) that 36 firms will move in, using 79.2 GWH annually in 1988, 21% more than their assumptions allow.

If FGE really believes that the industrial parks will fill up quickly, this would seem to be an ideal opportunity to install a central heating plant for each park, supplying steam and hot water to the occupants and efficiently generating electricity as well. Once the parks fill up, of course, laying pipes and locating the plant will become more difficult, and the economic advantages will be less pronounced if the occupants have already built their own boilers.

Even the small amount of inconsistent explanation which FGE supplies in reference to the Industrial Parks does not seem to be provided for Other Small Customers. Certainly, neither component is documented in detail commensurate with its importance in the forecast.

IV. NEPOOL FORECAST

Q: How has the NEPOOL forecast been introduced into this proceeding?

A: Without specifically identifying the NEPOOL forecast, various applicants have used it to support various assertions, including PSNH's statement that New England's capacity situation will be desperate without Seabrook (IR P-45), and Montaup's statement that New England will suffer a capacity shortage in the 1980's, even with Seabrook (IR M-118). In addition, New Bedford's industrial forecast simply applies the NEPOOL industrial forecast growth rate to New Bedford industrial sales (IR N-54).

Q: Is the NEPOOL forecast reliable?

A: No. This can be seen in three ways. First, the model on which it is based has numerous errors, including underestimates of the impact of electricity price on sales; incorrect formulation and estimation of equations; total neglect of load management, time-of-use rates, and other rate reform; inclusion of irrelevant and archaic consumption trends; and incorrect and pessimistic projections of appliance efficiency standards. In addition, there exists no comprehensive description of the NEPOOL model, as it was used to generate the 1979 forecast. Some crucial aspects of the model, such as the price forecast and the elasticities , seem to not be documented at all. Therefore, in addition to various obvious errors in the model, there may be many more which are hidden by the lack of public accountability. Our most recent comprehensive analysis of the NEPOOL model is attached, as Appendix B.

We are not alone in our criticism of the NEPOOL model. Studies performed by the Energy Systems Research Group for the New England Association of Public Utility Commissioners and by A.D. Little for the Maine P.U.C. have found the model to be deficient and upwardly biased.

Secondly, the NEPOOL model-based forecast has over-forecast growth in sales (apparently to each class) and in peak since 1975. Since the data on which the model was calibrated (that is, adjusted to fit) came from the 1970-76 period, it is hardly remarkable that its backcasts are reasonably close to actual results in that period. However, from the end of the calibration period to 1978, the model forecast 6.5% annual growth in energy output and 5.6% annual growth in weather-corrected peak, but actual growth was 2.8% and 2.1%, from Table 9. If the model continues to overestimate peak growth to this extent, peak will grow at 0.3% to only 16019 MW in 1989-90, leaving New England with a 45% reserve margin, even under the conservative assumptions of IR P-45.

Third, the NEPOOL model forecasts much greater demand growth than does the sum of the forecasts of the NEPOOL participants. Until the April, 1979 forecast, NEPOOL forecasts had always been constructed by summing the participant's forecasts, adjusting for diversity in peak demand, and adding 345-KV line losses. As Table 10 shows, eight of the nine largest NEPOOL participants (no 1979 forecast of winter peak is available for UI) have reduced their forecasts of 1987/88 peak by a total of 2412 MW betwen their 1978 and 1979 forecasts. Therefore, a NEPOOL forecast based on the old methodology would have fallen by at least that amount, and probably more, since other participants' forecasts have also fallen. Furthermore, in announcing NEESPLAN, NEES has further revised its forecast downward, by about 180 MW for 1987/88; this increases the drop in the eight companies' forecasts to about 2600 MW.

NEPOOL, on the other hand, has revised its 1987/88 peak forecast downward by only 454 MW. Therefore, NEPOOL expects over 2000 MW of demand that none of the participants expect on their own systems. NEPOOL's forecast is already several hundred megawatts too high, as Table 9 indicates, and even the member companies expect that error to increase.

The participants' forecasts are not really an adequate benchmark, in any case, since the participants themselves have generally overforecast since 1973. In D.P.U. 19494 (Phase I and II) we presented testimony demonstrating that the 1978 forecasts of all the participants listed in Table 10 (and UI and CVPS as well) were unreliable and upwardly biased. This conclusion was supported by several other witnesses with regard to Boston Edison in Phase I, and with regard to Central Maine Power, CVPS, and UI in Phase II (Testimony of J.K. Stutz and of J.P. Brainard, on behalf of Boston Clamshell). While the 1979 forecasts represent at least partial acceptance of our conclusions, upward biases remain, as we have indicated in our previous discussions of

EXHIBIT I

New England Seasonal Peak Loads and Energy Requirements
Actual Metered Vs. Model Derived and Weather Corrected
Summer and Winter Peaks Vs. Model Forecast

	Net Energy--GWH		Summer Peak Loads						Winter Peak Loads					
	Actual	Forecast	Actual Metered	Model Calibration Loads	Diff.	Weather Corrected Actual	Model Forecast	Diff.	Actual Metered	Model Calibration Loads	Diff.	Weather Corrected Actual	Model Forecast	Diff.
1970	61470	60402	10305	10972	677	10596	10674	78	11643	11052	(591)	11708	11183	(525)
1971	65208	63343	10915	10966	51	10856	11069	213	12135	11730	(405)	12514	12115	(399)
1972	70567	68638	11837	10963	126	11987	11919	(69)	13548	13013	(535)	13629	12979	(650)
1973	76202	73585	13079	13119	40	13167	12741	(426)	12852	12330	(522)	12770	12624	(146)
1974	73216	71531	12141	12399	250	12821	12143	(678)	12891	12406	(485)	13376	12677	(699)
1975	73700	71470	12842	12573	(269)	12514	12161	(353)	13908	13912	4	13812	13614	(198)
1976	78310	77000	13116	13320	204	13575	13125	(450)	14739	14395	(344)	14859	14379	(480)
1977	8.4 73781 (P)	81589 6.5	14234	14523	289	13712	13918	206	14846	14930	84	15363	15364	1
1978	~~82003~~	87375	14458	14588	130	14954	14896	(58)	15089 (P)			15500	16037	537
1979	83461	91861					15569						16595	
1980		95473					16108						17266	
1981		99462					16714						18036	
1982		103812					17409						18822	
1983		108256					18113						19755	
1984		113521					18958						20668	
1985		118639					19784						21502	
1986		123407					20552						22267	
1987		127840					21275						22989	
1988		131868					21932						23595	
1989		135317					22405						24120	

Annual Compound Growth Rates - %

	Energy	corr-fore	Summer Peak
1970 - 1973	6.8%		7.5%
1974 - 1978	5.1%		3.9%
1978 - 1989	4.1%	4.0%	3.8%
1979 - 1989	3.9%		3.7%

Winter Peak	[illegible]	Corr-fore
1970/71 - 72/73	7.9%	
1973/74 - 78/79	4.0%	
1978/79 - 89/90	4.1%	3.%
1979/90 - 89/90	3.8%	

P = Preliminary

Note: The Model was run with actual economic, demographic and weather data to develop columns 2, 4 and 10 and then rerun with expected weather for summer and winter to develop columns 7 and 13, for the periods 1970 through 1978.

Table 9: NEPOOL Model Historic Results

From: NEPOOL Forecast, 1979

COMPANY	1977/78 PROJECTED WINTER PEAK (1)	1987/88 PROJECTED WINTER PEAKS 1978 (2)	1979 (3)	% REDUCTION IN GROWTH OF WINTER PEAK (4)	MW REDUCTIO IN 1987-88 WINTER PEAK (5)
BECO @210	1786	2594	2386 2177	25.7%	208 +209
EUA	658	980	816	50.9%	164
NEGEA	613	925	838	27.9%	87
NEES	3018	5202	3980	56.0%	1222
with NEESPLAN			3708	68.4%	0 1506 !
NU 1980	3703	5342	5180 5026	9.9%	162 +154
CMP	1147	1886	1741	19.6%	145
PSNH	1156	2341	2101	20.3%	240
MMWEC	672	1116	932	41.4%	184
TOTAL	12753	20386	17974	31.6%	2412
with NEESPLAN c̄ NU 1980			17702	35.2%	2607 2970
NEPOOL FORECAST	15039	23443	22989	5.4%	454

Table 10: Comparison of NEPOOL Forecast with Participants Forecasts

(1) from 1978 L & C Report
(2) from participants' 1978 forecasts
(3) from participants' 1979 forecasts
(4) column (4) is calculated as follows:

$$(4) = \frac{(2) - (3)}{(2) - (1)}$$

(5) column (5) is the difference between (2) and (3)

the buyers' forecasts. In addition, we are aware of continuing biases in the forecasts of NU, BECO and MMWEC. We attempted to secure the documentation for PSNH's current forecast in this proceeding, but were denied it. Considering that PSNH has the highest forecast growth rate of any company listed in Table 10, and has the second-highest forecast MW growth (14% of the total post-NEESPLAN growth in Table 10), any bias in PSNH's forecast substantially impacts the sum of participants' forecasts. Appendix C to our testimony is our critique of PSNH's 1978 forecast; it is our understanding that the 1979 methodology was essentially the same as in 1978, so most of the criticisms apply to the current PSNH forecast. Therefore, the sum of participants' forecasts is almost certainly too high, implying that the NEPOOL forecast is overstated considerably more than 2000 MW by 1987/88.

In summary, NEPOOL appears to have created a model with numerous unjustified growth-producing assumptions. NEPOOL then utilized high short-run elasticities and large commercial conservation corrections to neutralize this excessive growth in the calibration period. Once the calibration period ends, the model grows much too rapidly. Continuation of the inflated trends, coupled with new growth-producing assumptions and errors, produces inflated forecasts, which are not consistent either with recent experience or with the participants' forecasts.

V. COST OF SEABROOK

Q: Are PSNH's estimates of Seabrook capital costs consistent with historical experience?

A: No. Econometric studies by NERA and Rand indicate that Seabrook will cost much more than PSNH claims. This conclusion is also supported by the historical tendency of architect/engineers and utilities to underestimate nuclear construction costs.

Q: Please explain how the NERA study indicates that PSNH's capital cost estimates are optimistic.

A: The NERA study (Exh. M-24) projects a capital cost of about $2245/kw (in 1990 dollars) for an 1150 mw first unit. This value is based on three very doubtful assumptions:

1. 5.5% general inflation, 1977-1990 (p.4),
2. 6% real escalation of nuclear costs, 1977-85 (p.7), and
3. no real escalation of nuclear costs, 1985-90 (p.7).

Considering that real nuclear costs actually increased by 10% annually from 1960 to 1977 (p.7), NERA's inclusion of cost estimates with 6% inflation from 1977 to 1985, and the exclusion of all escalation past that point, is completely unjustified by the historical record. The 5.5% general inflation assumption seems optimistic as well, at least in the short term. Removing both NERA's inflation and NERA's escalation, we find a 1977 estimate of

$$\frac{2245}{(1.055)^{13} \times (1.06)^{8}} = \$702/\text{kw (1977)}$$

for a first unit and

$$702 \div e^{.26953} = \$536/\text{kw}$$

for a second unit (see Table A-1). These figures are comparable to the extremes NERA presents for 1977 actual costs of $396 for an unusually cheap second unit to $902 for an unusually expensive first unit (see p.5).

Assuming a continuation of historic (10%) real nuclear escalation rates, inflation of 10% annually 1977-83, and 8% thereafter, the Seabrook units would cost:

$702 \times 1.1^{6} \times 1.1^{6} = \$2203/\text{kw}$ for Seabrook I, and

$536 \times 1.1^{8} \times 1.1^{6} \times 1.08^{2} = \$2374/\text{kw}$ for Seabrook II,

even on the scheduled in-service dates of 1983 and 1985. The total cost of the project would then be $5.3 billion dollars. If Seabrook II comes on line in 1989, the modified NERA formula predicts a cost for that unit of

$536 \times 1.1^{12} \times 1.1^{6} \times 1.08^{6} = \$4729/\text{kw}$,

which would bring the project cost to $8.0 billion.

Q: Does the Rand study support similar estimates?

A: Yes. In a study prepared for DOE (<u>Cost Analysis of Light Water Reactor Power Plants</u>, William E. Mooz. R-2304-DOE, June 1978), Rand derived the formula presented as Table 11. The 1976 dollars used in the report are the deflated values of actual annual expenditures, not of the final accounting cost, so the values given by the formula must be inflated to reflect the entire construction period.

Variable Name	Meaning	Co-efficient	Seabrook I [Seabrook II]	Value for Contribution to Cost/kw
Constant				-8885.5
CPIS	date of construction permit	141.34	76.5	10812.5
SIZE	in MW	-.21943	1150	- 252.3
Tower	cooling tower dummy	92.04	0	0
LOC 1	Northeast dummy	128.12	1	128.12
LN	ln of # of LWR plants built by A/E	-72.422	ln (6) = 1.79 [ln (8) = 2.08]	-129.8 [-150.6]
Cost in 1976 $/kw			Seabrook I Seabrook II	1673.0 [1652.2]

Table 11: Rand Formula Estimate of Seabrook Construction Cost

The Rand study used a steam plant construction deflator which increased in value at 8.01% per year from 1965-77 while the CPI increased only 5.59% per year in that period. Hence, we should add 2.4% to the general inflation rates we assumed, for steam plant inflation rates of 12.4% from 1977 to 1983 and 10.4% thereafter. The North Atlantic steam plant index actually increased ~~6.3% in 1977.~~ 11.1 from 1976 to 1978 Approximating the average cost index during construction as the average of the index at the time of the purchase of the nuclear steam supply system (1/73) and the index at the time of commercial operation, we have

1673 x [(~~1.063~~ 1.111 x $1.124^{\cancel{5}\,4.83}$ + .662) ÷ 2] = $2149/kw 2189
for Seabrook I and

1652.2 x [(~~1.063~~ 1.111 x 1.124^{5} x $1.104^{1.67}$ + .662) ÷ 2] = ~~$2375~~/kw 2489
for Seabrook II

on the 1983/85 schedule, and

1652.2 x [(~~1.063~~ 1.111 x 1.124^{5} x 1.104^{6} + .662) ÷ 2] = ~~$3399~~ 3528/kw
for Seabrook II, 1989.

These costs imply total project cost of $5.~~2~~4 billion to $6.4 billion. While this methodology agrees well with the modified NERA projection for the 1983/85 in-service dates, the difference in treatment of time (in-service date versus construction permit issuance) produces quite different results for the 1989 in-service date for Seabrook II. The two approaches' predictions of 1989 Seabrook II costs are approximately ~~75~~ 83% higher (Rand) and 1~~50~~46% higher (NERA) than

PSNH's estimate. Since both the date of construction permit issuance and the date of commercial operation must have some impact on regulatory impacts and real cost escalation, these two estimates bracket a range of reasonable cost projections.

Q: How does the past record of A/E cost estimates support the capital cost forecasts of the econometric models?

A: Of the seven licensed nuclear units in New England, we have been able to obtain the cost estimate histories for four. To date, the utilities have successfully suppressed the cost estimate histories for the other three plants, and the data provided by CL&P is somewhat vague. However, we do have enough data to estimate the magnitude of past errors in A/E cost estimates.

Table 12 presents the cost estimates for each of the four New England plants, from the time the construction permit was issued to completion. The Connecticut Yankee estimate was fairly accurate, being off by only about 1% per forecast year of construction time. More recent plants' estimates have been less successful. Even Millstone I's estimates were off by 5-8% per year despite the fact that this was a turnkey plant. Millstone II and Pilgrim I cost estimates were even further off, by 7-19% per year; the earliest (p~~a~~ost-permit) estimates were off by 16% (Millstone II) and 14.6% (Pilgrim, corrected for fuel

Plant	Estimate Date	Estimated In Service Date	Estimated Time to Completion (Yrs.)	Estimated Cost ($M)	Final Cost ($M)	Final Cost / Estimated Cost	Annual Myopia Factor	Actual In-service .Date	
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	
Connecticut Yankee	1963	1967	4	98.5	103.5	1.051	1.012	1/68	
Millstone 1	1966	1969	3	87.0	103.0	1.184	1.058	3/71	
	1968	1969	1	95.8		1.075	1.075		
Millstone 2	11/1970	4/1974	~~4~~ 3.42	240.0	434.0	1.808	~~1.160~~ 1.189	12/75	5.08
	11/1973	8/1975	~~2~~ 1.75	381.0		1.139	1.067 1.077		2.08
Pilgrim 1	6/68	9/71	3.25	131.7	233.153	1.770	1.192	12/72	
	6/68	9/71	3.25	149.7(1)		1.557	1.146		
	1/70	9/71	1.67	180.6		1.29	1.166		

Table 12: Cost Estimate Histories for Nuclear Units in New England

Note: (1) includes $18M for fuel
Column (8) is column (7) raised to the inverse of column (4), the annualized tendency to underestimate cost

assumption), with 3.25 to 4 year expected lead times. Applying a 15% annual correction for the forecast lead times for the January 1979 Seabrook forecasts yields:

$\$1.337B \times 1.15^{4.25} = \$2.422$ billion for Seabrook I
$\$1.472B \times 1.15^{6.08} = \$3.446$ billion for Seabrook II in 2/1985
$\$2.212B \times 1.15^{10.08} = \$9.054$ billion for Seabrook II in 2/1989

This correction yields approximately the same results as the econometric techniques for the total plant cost on the current schedule: $5.8~~8~~7 billion. Again, there is divergence on the cost estimate for the 1989 Seabrook II schedule, with this approach producing a higher estimate ($11.48 billion) then either of the others.

Q: Is it reasonable to expect that the capital cost of the Seabrook units will remain constant after they go on line?

A: No. The capital costs of the seven nuclear units in New England have increased at the average rate of $9480 per MW per year (1977$), as demonstrated in Appendix A. Allowing for the inflation rates we have been assuming, this would increase to $28783/mw-year by 1990, or 5.5 mills/kwh at a 60% capacity factor. If the same level of real replacements continues and the 8% inflation rate continues, the capital cost of the Seabrook units would increase by about $1.2 billion between their scheduled in-service dates and the year 2000, and by another $3.1 billion between the year 2000 and the end of a 28-year useful life.

Q: Are PSNH's projected in-service dates for the Seabrook units reasonable?

A: It seems unlikely that the plants will be completed by the time PSNH expects them to be. Construction periods for nuclear power plants have increased dramatically in the last decade. Table 13, taken from a General Accounting Office study, indicates that nuclear units took twice as long to build in 1978 as they did before 1970. Table 14 lists every plant for which the Electrical World 1979 Nuclear Plant Survey (January 15, 1979 pp. 71-81) gave an in-service date of 1978 or 1979; it appears that the construction duration that PSNH is forecasting for Seabrook (81 months for Unit I, 103 months for Unit II) is somewhat optimistic even at the present time.

The Rand study discussed above derives an equation to estimate the time from construction permit to operating license, in months. In Table 15, this formula is evaluated for the Seabrook units. Including Rand's estimate of 7.5 months from operating license to commercial operation, this projection of past experience indicates that the Seabrook units would be expected to come on line 119 months after issuance of construction permits, or in June of 1986. Of course, these figures do not reflect either the Seabrook permit suspensions or PSNH's current or future financial difficulties.

Calendar Year	Number of reactor units	Average Construction duration for first units
Before 1970	12	46.0 months
1970	4	47.6 months
1971	4	54.9 months
1972	5	66.0 months
1973	7	68.0 months
1974	10	66.9 months
1975	3	78.7 months
1976	4	91.4 months
1977	4	90.4 months
1978	4	92.3 months (1)

Table 13: Construction duration trends

From: Tennessee Valley Authority Can Improve Estimate And Should Reassess Reserve Requirements for Nuclear Power Plants, General Accounting Office, PSAD-79-49, March 22, 1979, p.15.

(1) projected; apparently, not all the units came on line as scheduled

	(1) Date of			Months from Construction Permit to	
Plant	Construction Permit	Operating License	Commercial Operation	Commercial Operation	August 1980
Hatch 2	12/27/72	6/13/78	9/5/79	80	
Arkansas 2	12/6/72	9/1/78	NY (2)	8~~4~~7 (3)	
LaSalle 1	9/10/73	NY	NY		83
McGuire 1	2/28/73	NY	NY		90
Cook 2	3/25/69	12/23/77	7/1/78	111	
Three Mile Island 2	11/4/69	2/8/78	12/30/78	110	
Diablo Canyon 1	4/23/68	NY	NY		148
Diablo Canyon 2	12/9/70	NY	NY		116
Salem 2	9/25/68	NY	NY		143 (4)
Sequoyah 1	5/27/70	NY	NY		123 ~~(5)~~
North Anna 1	2/19/71	11/26/7~~0~~9	6/6/78	89	
North Anna 2	2/19/71	NY	NY		114
				95.4	117

Table 14: Construction Duration of Recent Nuclear Plants and Those Near Completion

Notes:
(1) from NRC Gray Books
(2) NY = not yet, as of 9/30/79
(3) assumes ~~12~~ 3/1/~~79~~ 80 commercial operation, from ~~APL 4th quarter report~~ Arkansas Div. of Energy Cons & Rate Advocacy Newsletter Nov/Dec 1979
(4) 4th quarter report for Delmarva P&L reports 10/80 earliest COD
~~(5) listed as completed,~~

Variable Name	Meaning	Co-efficient	Value for Seabrook I	Contribution to construction duration
Constant				-270.8
CPIS	date of construction permit	4.5478	76.5	347.9
SIZE	in MW	.043643	1150	-50.2
BW	Babock & Wilcox dummy	13.065	0	
LN	ln of number of LWR Plants built by A/E	-8.0039	1.94 (1)	ok -15.5
construction duration, construction permit to operating license, in months or 9 years, 4 months				111.8

Table 15: Calculation of Interval Between Construction Permit and Operating License, Seabrook Units as predicted by Rand Study

(1) average for Seabrook units

While PSNH predicts that the units will be completed 27 months sooner (with an average in service date of March 1984), this prediction can not reasonably be given much weight. Similar predictions for other plants in New England have been extremely unrealistic. In March 1971, Pilgrim I was estimated to be eight months from commercial operation but was actually 21 months from commercial operation. In-service date estimates for Millstone II showed similar errors; unfortunately, NU has insisted on keeping this information (IR BE-II-600-1, D.P.U. 19494) confidential, so we cannot discuss specific numbers. Between December 1976 and January 1979, the Seabrook units were subject to only four months of construction suspension but the forecasted in-service dates were moved back by an average of 16 months. There is no reason to believe that the historical trend of increasing nuclear construction times and the historical tendency for utilities to underestimate nuclear construction duration will suddenly cease.

Q: What is the significance of the in-service dates for the Seabrook units?

A: The in-service date is important for at least three reasons. First, the units will not be displacing oil (or supplying capacity) until they come on line; the more remote that date is, the less valuable the current investment is. Second, the later the units come on line, the higher the associated AFUDC. Third, the NRC has traditionally been more willing to impose new requirements on units that are not yet operating, so delays in the in-service date may increase the scope (and hence the direct cost) of the project. This last tendency is recognized in the NERA formula, which predicts that, if the units come into service 27 months later than currently scheduled (that is, in 7/85 and 5/87), they will cost $1.1^{2.25}$ = 1.239, or 23.9% more due to real escalation, in addition to $1.08^{2.25}$ = 1.189, or 18.9% more due to inflation (at 8%), for a total increase of 47.3% over our previous NERA-based estimates, or about $3246/kw for Seabrook I, $3498/kw for Seabrook II, and $7.8 billion for the entire project.

Q: Do any other cost estimate histories of nuclear plants outside of New England, particularly any plants constructed by UE & C, Inc., support your previous testimony?

A: Yes. As the attached Tables 16 and 17 clearly show, cost estimates for the Salem Units I, II, and III have increased approximately 160 ~~250~~% starting with an initial estimate of $430 ~~342~~ million and ending at $1.21 billion, with the second unit still over three years from commercial operation. Two months before receipt of a construction permit, Salem I was expected to be 43 months from commercial operation; it actually took 106 months. If the 1/78 Seabrook I estimate (53 months) is equally inaccurate, the unit would become commercial in July of 1988.

Likewise, Three Mile Island II, which received a construction permit in November, 1969, more than tripled in price by 1977, when it was still a year from commercial operation. The construction schedule at the time of the construction permit was 53 months, the same as the 1/78 Seabrook schedule; commercial operation was actually achieved only after 109 months, and lasted only three months. Perhaps TMI II was put into commercial operation prematurely.

Both the Salem and Three Mile Island plants were constructed by U E & C.

The same sort of trends can be observed for the three nuclear plants currently under construction in New York State. Table 18 indicates that cost estimates for these plants have been increasing by as much as 20% or 30% per year, and that the in-service dates have been moving back at almost one year for every year that elapses.

EXHIBIT IX-1

PUBLIC SERVICE ELECTRIC AND GAS COMPANY
SALEM PROJECT

TABULATION OF ESTIMATES FOR SALEM NUCLEAR GENERATING STATION UNITS NO. 1,2, AND 3

Date of Estimate	Estimate Title	Kilowatts Net	Amount*	$/KW Net	Service Dates
8/1/68	Salem Official Estimate**	2,262,000	342,300,000	151	
	One 1090 Net MWe Unit				3/72
	One 1112 New MWe Unit				3/73
	Three 20 Net MWe Gas Turbines				5/71
9/1/69	Salem Revised Estimate***	2,262,000	430,000,000	190	
	One 1090 New MWe Unit				3/72
	One 1112 New MWe Unit				3/73
	Three 20 Net MWe Gas Turbines				5/71
1/4/71	Salem Operating Study Estimate***	2,242,000	500,000,000	223	
	One 1090 Net MWe Unit				12/73
	One 1112 Net MWe Unit				12/74
	One 40 New MWe Gas Turbine				5/71
7/1/71	Salem Revised Estimate***	2,245,000	550,000,000	245	
	One 1090 New MWe Unit				12/73
	One 1115 Net MWe Unit				12/74
	One 40 Net MWe Gas Turbine				6/71
7/1/72	Salem Revised Estimate***	2,245,000	685,000,000	305	
	One 1090 Net MWe Unit				3/75
	One 1115 Net MWe Unit				3/76
	One 40 Net MWe Gas Turbine				6/71
7/1/73	Salem Revised Estimate***	2,245,000	800,000,000	356	
	One 1090 Net MWe Unit				9/75
	One 1115 Net MWe Unit				9/76
	One 40 Net MWe Gas Turbine				6/71
7/1/74	Salem Revised Estimate***	2,245,000	1,045,000,000	465	
	One 1090 Net MWe Unit				12/76
	One 1115 Net MWe Unit				5/79
	One 40 Net MWe Gas Turbine				6/71
7/1/77	Salem Revised Estimate***	2,245,000	1,210,000,000	539	
	One 1090 Net MWe Unit				6/77
	One 1115 Net MWe Unit				5/79
	One 40 Net MWe Gas Turbine				6/71

* These amounts do not include the Switchyard, Fuel, or Allowance for Funds Used During Construction.

** Estimate did not include escalation.
*** Includes Estimated Escalaton to Job Completion.

Table 16: From Construction Management Audit of Salem Nuclear Generating Station Unit No. 1., Theodore Barry and Associates, May 1977

TMI-2 COST ESCALATION*

- 21 cost and in-service date estimates were prepared for TMI-2 between 1969 and 1977:
  - Total cost escalated from $190M to 687 $659M** or an increase of $469M (247%).
  - In-service date slipped from 5/73 to 12/78 5/78** or a 5-year total slippage.
- Cost and schedule escalation occurred consistently on a year-to-year basis from 1969-1974:
  - Cost escalation continued during 1975-1977, however, at a reduced pace.
  - In-service date of 5/78 has not changed since 9/74.
  - Reduced rate of cost escalation and reliability of in-service date correlates with date (9/74) that TMI-1 began commercial operation.

SUMMARY OF COST/SCHEDULE ESTIMATES

Year	Number of estimates	Initial cost	Ending cost	Annual escalation	In-service date	Annual I.S.D. slippage (months)
1969	Original	$190M	$ -	$ -	5/73	-
1969	2	190M	214M	24M	5/74	12
1970	4	214M	285M	71M	5/74	-
1971	3	285M	345M	60M	5/75	12
1972	2	345M	465M	120M	5/76	12
1973	1	465M	525M	60M	5/77	12
1974	3	525M	580M	55M	5/78	12
SUBTOTAL	16	190M	580M	390M	5/78	60
1975	1	580M	630M	50M	5/78	-
1976	2	630M	637M	7M	5/78	-
1977	2	637M	659M	22M	5/78	-
TOTAL	21	$190M	$659M	$469M	12/78 5/78	60

* Escalation is defined as an increase in dollar cost or delay of an in-service date over a previous estimate. This term and its explanation is used in the same sense throughout this report.

** Estimates as of 12/77 are subject to change by the company.

Note: This entire section of the construction review report was prepared prior to the final delay caused by the malfunctioning of certain safety values. The current in-service estimated date is November 1978 and the total cost approximately $687 million.

Table 17: From Review of the Three Mile Island - Unit 2 Construction Project, Touche Ross & Co., October 1978

Year.	Shoreham inservice		Nine Mile Pt. 2 inservice		Sterling	
of estimate	$1000	Year	$1000	Year	$1000	Year
1974	506	1978	511	1979	281.36	1978
1975	699	1979	700	1981	935	1982
1976	699	1979	1013.4	1982	1130	1984
1977	------------------not available-----------------					
1978	1188	1980	1521.6	1983	1490	1986
1979	1337	1980	1977.4	10/1984	1777.3	1988
1980	1581	5/81	2048.0+	[illegible]/1986	canceled	
Construction permit date	4/15/73		6/24/74		9/ /77	

Table 18: Cost Estimate History, New York State Nuclear Plants

Source: Long Range Plan (149-B Report), New York Power Pool, April, various years.

add Cayuga
Midlands

Q: Are PSNH's estimates of Seabrook capacity factors reasonable?

A: No. Statistical projections of nuclear capacity factors based on actual operating experience, indicate much lower capacity factors than PSNH or any of the other applicants expects. Three such studies, all utilizing data through 1977, are the Council on Economic Priorities (CEP) Nuclear Plant Performance/Update 2, (June 21, 1978), a Sandia Laboratories study for the NRC (Robert G. Easterling, Statistical Analysis of Power Plant Capacity Factors NUREG/CR-0382, February 1979), and the NERA study presented as Exh. M-24.

The CEP study projects an average capacity factor for the first ten years of operation for Westinghouse 1150 MW reactors at 54.8%, based on statistical analysis. This estimate is subjectively increased to 57% to allow for "a modest learning curve".

The NRC study projects average capacity factors for 1150 MW PWR's as 51.~~0~~9% in the second full year of operation, 54.9% in the third full year, and 58.2% thereafter. All results for the first partial year and first full year of operation are excluded. Assuming that first year capacity factors are as good as second year capacity factors, a plant with a 28-year life would average 57.6% over its life.

The NERA study presents capacity factor estimates of 63.6% for 1100 MW plants and 63.1% for 1200 MW plants

(Table 2), based on commercial PWR's, and again excluding initial partial years of operation. These figures appear to represent averages of the values generated by the regression equation presented in Table A-2 of Exh M-24, which predicts 1150 MW plant capacity factors of 54.9% in year one, rising to 66.5% in year 28.

Therefore an average life-time capacity-factor estimate for units like Seabrook of about 60% would seem reasonable, with 55% and 65% representing (respectively) somewhat conservative and optimistic bounds for average estimates. There is a great deal of variation from the average, however; the NERA study could explain only 28% of the variation in the data, and the NRC study derives 95% prediction intervals of about ±10% in years 2 to 5, ±8% in years 2 to 10, and ±7.3% for years 2 to 28. Roughly speaking, the NRC results predict that 19 out of every 20 nuclear units of the Seabrook size and type would have lifetime capacity factors between 50.3% and 64.9%, with the 20th unit having a capacity factor outside that range. Actually, the variation would be somewhat larger, due to the greater variation in the first partial year and the first full year.

Q: Do you have any comments regarding the basis of the companies' capacity factor projections?

A: EUA relies in part on a table copied from an NRC Gray Book (Ex. M-55), which shows nuclear capacity factors to be essentially level through the sixth year of life but rising dramatically in the seventh and eighth year of life. Mr. Gmeiner failed to note, however, that since the data was only collected up to 1975, the seventh year and eighth-year data represents only two plants, San Onofre I and Connecticut Yankee. Since Connecticut Yankee has been one of the most reliable plants in the country, any data set in which it represents half the data is apt to be better than average. In addition, these plants are respectively 37% and 50% the size of one of the Seabrook units, and capacity factor declines rapidly with plant size. Therefore, the last two years of that table can not be considered as relevant and appropriate predictors for the performance of the Seabrook units.

EUA also relies on analysis (Exh. M-55) of nuclear capacity factors for New England and the nation. This analysis uses capacity factors based on maximum dependable capacity (MDC); Mr. Gmeiner then argues that the results for the Yankee plants can be extrapolated to the Seabrook units because Yankee Atomic has had some involvement in designing and constructing the Seabrook units. This analysis and argument has three serious flaws.

First, as Mr. Gmeiner admitted on cross-examination, the 1150MW rating for the Seabrook units is a design electrical rating (DER), not an MDC (Tr. XX-117). The DER is generally greater than the MDC for any particular unit; for only about one nuclear plant in five are they equal, and in only one case (Pilgrim) does the MDC exceed the DER. Therefore, capacity factors based on MDC will generally be greater than those based on DER's; in forecasting the power output of a plant for which the MDC is not known (such as Seabrook), it is essential that a DER-based capacity factor be used. Contrary to Mr. Gmeiner's assertion that "it usually takes you maybe three years to get there [MDC up to DER], maybe four years" (Tr. XX-116), many older plants have not achieved this equivalence of ratings. Humboldt Bay has been retired after fourteen years without getting its MDC up to its DER; Connecticut Yankee has not done it in 12 years; nor Big Rock Point in 17 years; nor the Dresden units (1, 2, or 3) in 19 years, 9 years, or 8 years; nor Lacrosse in 11 years; nor Oyster Creek 1 in 10 years. Table 19 restates portions of Exh. M-55, and shows that the appropriate capacity factors for comparison with Seabrook are (except for Pilgrim) all lower than those presented by EUA, by as much as 5.7 percentage points (for Connecticut Yankee). The capacity-weighted average for the Yankee plants is 2.7

points lower than EUA's figure.

The second error in this portion of EUA's analysis lies in the statement that the Yankee units and the Seabrook units were designed, and that their construction was and is supervised, by Yankee Atomic. EUA has not offered any proof of this assertion, nor have they offered any evidence that the good performance of the two exceptional Yankee plants (Rowe and Connecticut) are in any way related to such design and supervision, as opposed to good fortune and greater contractor care in these early demonstration units. Indeed, we have not found any indication in normal industry sources that Yankee has had any design or supervisory role in any plant. The NRC Gray Books, the Nuclear News "World List of Nuclear Power Plants" (August, 1979), and the Electrical World "1979 Nuclear Plant Survey" (January 15, 1979), all indicate that certain utilities act as their own architect/engineers and/or constructors, in whole or in part. Such utilities include Consolidated Edison, LILCO, Niagara Mohawk, PSE & G, Commonwealth Edison, Detroit Edison, American Electric Power, Northern States Power, Duke Power, the TVA, and others. None of these sources attributes any such role to Yankee Atomic in any plant.

Third, the Yankee plants are all smaller than the Seabrook plants, and capacity factor decreases with size.

The NERA study predicts a 32.1% point difference in the capacity factor of units of the size of Yankee Rowe and Seabrook, and 5.8% difference between Connecticut Yankee and Seabrook. The NRC study predicts corresponding differences of 21.5% and 12.7%. Correcting the cumulative DER capacity factors of the <u>best two</u> Yankee plants to reflect Seabrook's DER produces capacity factor estimates of 41.2% to 51.8% (based on Rowe) and 63.8% to 70.7% (based on Connecticut Yankee), a range which neatly straddles the 50% to 65% range predicted by all studies quoted above.

PSNH claimed to have derived its capacity factor projections from "New England and national data". Since PSNH was unable to provide any of this data, it is not possible to determine why PSNH's projection is so much more optimistic than those of other analyses which actually used the available data.

Fitchburg and NEGEA use NEPOOL capacity factor projections, which do not seem to be documented in any way.

Plant	Capacity Factor (DER) cumulative 9/79	DER
Connecticut Yankee	76.5	575
Yankee Rowe	73.3	175
Vermont Yankee	66.6	514
Maine Yankee	65.2	825
Average Yankee	69.3 (DER weighted)	---
	70.4 (simple average)	
Pilgrim	55.9	655
Millstone I	63.1	660
Millstone II	60.6	870

Table 19: Restatement of Exh. M-55 to Design Electrical RatingFrom NRC Gray Book, October 1979

Q: Are the Seabrook O & M expense projections presented by the applicants reasonable?

A: No. Basically, the applicants have failed to account for the remarkable rate at which nuclear O & M expenses have been increasing over the last decade. Table 20 presents the least-squares estimates for linear and compound (geometric) growth in real 1977 dollars for each nuclear plant in New England. The data utilized is presented in Appendix A. Since all these trends are net of general inflation, it is clear from Table 20 that nuclear O & M is rising much faster than other prices.

It does not appear from this data that O & M expense is significantly related to plant size, but such a relationship might appear in a larger sample. On the other hand, there does appear to be a vintage effect: the oldest plants (Rowe, Connecticut Yankee) have lower 1977 O & M and lower growth rates than average, while the most recent plant (Millstone 2) has much higher and faster-growing O & M. This phenomenon may reflect the greater complexity of plants built to later, and stricter, safety standards. It may also have resulted from a gradual relaxation in design and construction quality, as vendors and contractors recognized that the nuclear construction business was rapidly declining, and that earlier efforts to establish market position were no longer justified; by the time a firm's reputation for quality work (or the inverse) could be established, the flow of new orders would be insignificant. Therefore, Millstone 2 would seem to be a better predictor of Seabrook O & M than would the older Yankee plants.

Nonetheless, it is possible that the Millstone 2 results are simply an aberration, and should not, on the basis of only three years' data, be accorded excessive weight. To be very optimistic, we have included all seven plants in the "New England averages"; for comparison, we have calculated the corresponding averages for the Yankee plants, even though we do not believe that these would be reasonable predictors for Seabrook O & M.

As Table 21 demonstrates, the geometric trend cannot continue for the entire expected life of the Seabrook plants; if it did, towards the end of their lives, the plants would cost more to maintain annually than they did to build, even in real terms. An alternative interpretation of the compound growth extrapolation would be that the plants will become too expensive to continue operating by the end of the century, and will be shut down after only 10 or 15 years. This interpretation is consistent with the experience of such early commercial plants as Humboldt Bay and Indian Point 1, which have apparently left service permanently after only 10 14 years and 12 years, respectively.

	Linear			Geometric		
Plant	1977 (1) Value	Annual (3) Increase	R^2	1977 (1) Value	Annual real Increase (%)	R^2
Yankee Rowe	6,254	491	.888	6,322	12.23	.897
Conn. Yankee	~~4,892~~ 11,[illegible]8	~~316~~ 718	.663	~~5,138~~ 11,677	11.15	.653
Vermont Yankee	9,624	751	.968	9,598	9.35	.933
Maine Yankee	8,346	777	.676	8,175	10.77	.655
Average Yankee	8836 ~~7,279~~	685 ~~584~~		8943 ~~7,308~~	10.87	
Millstone 1	14,824	1,720	.834	15,146	20.47	.791
Millstone 2	17,867	5,166	.9998	17,351	34.78	.990
Pilgrim	14,632	1,444	.819	14,577 (2)	15.72	.820
New England Average	11,890 ~~10,920~~	1,581 ~~1,524~~		11,835 ~~10,901~~	16.35	

Table 20: Least-Squares Projections of Nuclear O & M

(1) as estimated by least-squares equation; 1,000's of 1977 $
(2) includes $1929 for refueling; only $12,648 is subject to real escalation
(3) 1,000's 1977 $

The linear trend indicates that O & M will rise from 7 mills/kwh in the first year of the plant's lives to 176 mills by the 28th year. Even using the more conservative extrapolation method, ignoring vintage effects and the impact of the accident at Three Mile Island, we find O & M trends much higher than those used by the applicants in this proceeding.

Each Seabrook Unit O & M in	Linear Extrapolation	Geometric Extropolation(2)
1984 current $1,000	41,304	59,206
mills/kwh (1)	6.8	9.8
1998 current $1,000	241,220	1,437,488
mills/kwh	39.3	237.8
2012 current $1,000	1,060,683	36,052,462
mills/kwh	175.5	5,814.3
average O & M over 28-yr. life, 1984 $1,000	82,126	885,341
mills/kwh	13.6	146.5

Table 21: Linear and Geometric Extrapolation of New England Nuclear O & M Experience to the Seabrook Units.

(1) assumes 60% capacity factor
(2) a portion of refueling expense is assumed to be constant, due to nature of Pilgrim estimate.

Q: Have you calculated the total cost per kwh of power from Seabrook implied by the preceding results?

A: Yes. Using an 18% carrying charge, a 60% average capacity factor, the most favorable cost projections above, average real O&M costs in 1985 dollars and 8 mils/kwh for fuel, we find a total cost of around 10¢/kwh for Seabrook I and 11¢/kwh for Seabrook II, about a quarter of which is subject to inflation. If capacity factor is below expectation, if the plants do not come on line as scheduled (which is quite likely), if the capital costs prove to be closer to the higher estimates, if O & M follows the geometric trend, and/or if the plants do not last for 30 years, the cost per kwh could easily be twice that great, with a larger O & M component subject to inflation.

Q: Do these estimates include any effect of the accident at Three Mile Island?

A: No. The only impact of Three Mile Island recognized above is the delay of the in-service dates of a few of the plants listed in Table 14, which does not explicitly affect the total cost calculations above. If legislative, regulatory, or other reaction to the accident extends construction times, increases initial capital costs, accelerates interim replacements or the growth in O & M, or lowers capacity factors, the cost of power from Seabrook will tend to be greater than the estimates given above.

Q: Are there other disadvantages to nuclear power plants, beyond the costs discussed above?

A: Yes. On both short-run and long-run bases, nuclear power plants are unreliable and highly variable. As a result of their large size and high forced-outage rate, nuclear units require considerable back up. Even NEPOOL studies, such as those reported in IR F-40, indicate that about 2 MW of nuclear capacity are necessary to reliably support 1 MW of demand; in essence, nuclear capacity requires a 100% reserve margin.

But required reserves reflect only short-run reliability problems. In addition to fluctuations in performance over time, nuclear units vary considerably from one another. Because these plants are so large and expensive, any significant adverse variation from average performance can create quite serious problems. There is no way of knowing in advance whether a particular unit will be exceptional, such as Connecticut Yankee, or a lemon, such as:

Palisades, which has operated at a 38% capacity factor for the first eight years of its life;

Beaver Valley, which for the first three years of its life has had a 34% capacity factor and a 50% forced outage rate;

Indian Point, which operated for only 12 years;

Humboldt Bay, which operated for only 10 years;

Arkansas 2 or Hatch 2, each of which took over a year to reach commercial operation after receipt of their operating license; or

Three Mile Island 2, which operated for only three months before the accident, and does not seem likely to operate again for at least a few years, if ever.

VI. ALTERNATIVES

Q: If Seabrook is as expensive as the historical trends presented above would indicate, are there cheaper ways to generate power or reduce demand?

A: Yes. There appear to be a large number of such techniques, including conservation techniques on customers' premises, conservation techniques applied on the utility system, non-electrical energy production technologies, and electrical generating techniques. A few of these are discussed below.

In addition, there exists techniques for saving oil in existing generating facilities. If reduction of dependency on imported oil is a primary concern to the applicants, they might more profitably invest the vast sums which Seabrook would consume, in conversion of their generation facilities to wood or coal firing, to combined cycle operation or to cogeneration. Indeed, from the viewpoint of a service territory, state, or region, it would be more cost-effective to save oil by insulating oil-heated structures than by building Seabrook.

Q: Are conservation and load management techniques equivalent to providing similar amounts of energy and capacity through construction of new generators?

A: No. In general, the conservation and load management techniques are superior. New England is unlikely ever to experience the rapid loss of 1000 MW of conservation (insulation, for example), but 1000 MW of Seabrook will frequently become unavailable, quite quickly and with little warning. Increased motor efficiency can not be disconnected from demand by a transmission failure; Seabrook can. Most conservation procedures become effective soon after funds are expended on them; Seabrook will probably be under construction for over a decade before it starts to reduce oil use.

Mr. Gmeiner seems to believe that only "uninitiated" observers consider conservation and load management to be substitutes for new central-station generating capacity. The "uninitiated" appear to include not only the authors of <u>Energy Futures</u> and of NEESPLAN, but also the following electric utility companies:

Kansas Power and Light
Atlantic Electric
Florida Power and Light
Savannah Electric and Power
Central Vermont Public Service
Duke Power
Pacific Gas and Electric
Arizona Public Service
General Public Utilities

Q: Have the applicants pursued the development of alternatives as vigorously as they have pursued the acquisition of Seabrook capacity?

A: Not at all. By and large, the buyers seem to expect alternative capacity and energy sources to be presented to them, ready to go on line, without any significant prior investment or risk on the part of the utility. Indeed, the buyers have not been willing to offer fair rates, or even <u>any</u> firm rates, for purchased power or capacity from proposed installations. Any regulatory, institutional, or technical problem is generally regarded as a barrier to development, as is any significant uncertainty in cost.

With regard to Seabrook, the buyers' attitudes are considerably different. They are willing to expend considerable effort to acquire permission to buy a share of a plant that may or may not ever be completed; whose final cost is not known to, or controllable by, the buyers; which commits them to indefinite investments for indefinite periods; which still faces numerous institutional, regulatory, and technical obstacles; and for which they must pay, whether they receive any power or not.

The FGE study of hydro sites is a partial exception to this rule; FGE actually appears to be making an effort to develop some capacity. Even in this case, FGE seems willing to abandon the hydro sites in New Hampshire in the face of a regulatory problem.

Q: Are there conservation techniques which will save energy for less than the cost of producing new energy through construction of nuclear capacity?

A: Yes. Assuming the fixed charges NEGEA uses in its analysis of nuclear capital cost, adding 9 inches of loose cellulose on top of six inches of existing fiberglass attic insulation saves electricity at around 4.2¢ to 4.7¢ per kwh in various portions of EUA's service territory, and about 4.2¢ in Fitchburg's territory. Contrary to EUA's assertions, the large number of electrically heated homes with 6" attic insulation are not well insulated by today's standards, additional insulation is economically justified, and the effects of added insulation will not be "negligible" (Exh. M-10, p. II-9). Nine additional inches of insulation would save about 1660 kwh/year for a house with 1200 sq. ft. of ceiling in Brockton, for example.

Using a DOE estimate of 400 kwh/year savings from water heater tank insulation, an NU estimate of $30 for ready-made insulation; and a rather high fixed charge rate of 25% (to compensate for the short life of the water heater), it costs only 1.9¢/kwh to save electricity by insulating existing water heaters. If one accepts DOE's estimate of less than $5 for insulation and tape, the cost is about 0.3¢/kwh.

The Nola Power Factor Controller is currently being advertised for direct sale by mail for about $30, and is claimed to reduce the energy consumption of motor-driven appliances by 30%. Even assuming the utilities could not obtain the device at a lower cost (or that actual energy savings are proportionally lower than advertised), this is equivalent to 2¢/kwh saved for an average refrigerator, 1.8¢/kwh for a freezer, 1.7¢/kwh for a central air conditioner, and 1.6¢ if used on a room air conditioner for four months and on a freezer for the rest of the year (using EUA's estimates of average use per appliance throughout). If the device is only a half or a quarter as effective as claimed,it would still save considerable amounts of energy at much lower costs than Seabrook capacity, even in residential applications. If the energy used by refrigerators and freezers projected by EUA for its service territories were reduced by even 10%, about 33,650 MWH of sales would be saved in 1988. At 20% marginal losses and a 60% nuclear capacity factor, this is the equivalent of about 8MW of Seabrook capacity. Similar savings cannot be estimated for NEGEA or Fitchburg, since they do not forecast appliance saturations. Apparently, the payback is even better on large industrial and commercial motors.

Q: Are there other promising conservation techniques which are more consistent with traditional utility activities?

A: Yes. Such techniques include rate reform, conversion of master-metered apartments and businesses to individual meters, and voltage control.

Q: Please describe how rate reform can result in energy conservation?

A: It is well established, on theoretical, practical, and empirical grounds, that consumption of electricity is primarily responsive to the marginal price of electricity, rather than customer charges or other intra-marginal charges. Raising the tail block price by 10% should reduce sales by some 8% over the next decade or so at no cost to the utility and, if intra-marginal costs are similarly reduced, without increasing (in fact, reducing) customers' electric bills. As long as the marginal rates charged to customers for electrical energy are below the real costs of building and operating the facilities necessary to provide that energy, customers are being encouraged to waste energy and discouraged from implementing conservation measures which are cheaper than the new capacity. Yet at least three of the applicants' affiliates (Cambridge Electric, Brockton Edison, and New Bedford Electric) have, in recent rate cases, proposed lowering marginal prices (which are already well below marginal costs) and increasing customer charges. This is not the behavior of companies concerned (as Mr. Fox and especially Mr. Gmeiner would have us believe) about the future availability of capacity and fuel; this is the behavior of companies concerned with encouraging uneconomical sales, to justify capacity additions which would not otherwise be needed.

Energy use can also be reduced by collecting industrial and commercial revenues through energy charges, which encourage conservation, rather than demand charges, which primarily encourage shifting of loads (but not necessarily off of system peak). If system costs vary considerably by time of day, time-differentiated energy rates can reflect this variation, and encourage appropriate levels of conservation at all times; demand charges cannot do this. None of the buyers in this proceeding have demonstrated any interest in replacing inefficient demand charges with efficient energy charges, nor have any of them been exactly zealous in pursuing mandatory time-of-use rates. Again, the sincerity of the utilities' concern about future supplies of capacity and energy is doubtful, in light of their inaction in rate reform.

Q: How does conversion of master-metered apartments and businesses to single meters conserve energy?

A: The master-metered electricity user faces a zero price of energy, and therefore has no incentive to use it wisely.

Federal Energy Administration figures (UCAN Manual of Conservation Measures, Conservation Paper #35) suggest that single-metered apartments use 25% less energy than master-metered apartments, while Boston Edison data indicates that single-metered apartments use only about half the heating energy of master-metered units. If the actual reduction is 35%, converting seven of Fitchburg's ten master-metered apartment buildings would save about 1,750 MWH annually, 1.8% of FGE's 1978 residential sales, and equivalent to the output of about 400 kw of Seabrook capacity. We cannot do the same calculation for the other buyers, since they have not even bothered to collect information on the number and usage of master-metered apartments, let alone study the economics of converting them.

Of course, if all electric customers were charged the full cost of producing additional electricity and supplying it to them, the owners of master-metered residential (and commercial) facilities would have a greater incentive to convert their own units.

Q: Please describe the potential energy savings and costs of voltage control.

A: Exh. M-47 , which Mr. Gmeiner has accepted as representing the position of EUA on voltage control, indicates that it is very attractive. Since AEP reduced voltage for only

4 hours a day, the experiment showed savings of only 0.54%, including some circuits for which there were negative savings. The cost of applying a control system (apparently more flexible than that used in the experiment) to the entire AEP system was estimated to run into the "tens of millions" of dollars. Taking a series of worst-case assumptions, including AEP's short and fixed 5% voltage reduction, inclusion of substations which demonstrate negative savings, and a cost estimate of $100 million (the high end of tens of millions); AEP's total 1978 retail sales of 63360 ~~M~~GWH, and a fixed charge rate of 20%, we get a cost per kwh saved of 5.8¢.

Results from Southern California Edison indicate that continuous reduction of voltage by only 2-3% can save 2% to 6% of sales (and demand), with positive savings on all lines; this is consistent with AEP's results during the 4-hour period of actual voltage reduction. Combining these results with the other data above yields a cost estimate per kwh saved of 0.5¢ to 1.6¢. If EUA's forecast 1988 retail output (4,432 GWH) is reduced 4.0%, it would save 177 GWH, equivalent to ~~37~~ 34 MW of Seabrook output. For FGE (602.1 GWH output), the savings would be 24 GWH and 5 MW of Seabrook, while for NEGEA it would be 179 GWH and ~~37~~ 34 MW of Seabrook.

Q: Can cogeneration replace oil-fired capacity at a lower cost than Seabrook capacity?

A: It would appear so. The Final Report of the Governor's Commission on Cogeneration (Cogeneration: Its Benefits to New England, October, 1978) gives cost estimates for numerous combinations of cogeneration technologies, heat demands, and capacity factors. These cost estimates include capital costs, O & M, and data from which heat rates can be calculated. Somewhat higher (but less specific) estimates of capital costs and heat rates are given in an article entitled "Cogeneration" (Power Engineering, March, 1978, pp. 34-42). While there are some complications in analyzing the cost of replacing inefficient conventional oil-fired generation with efficient oil-fired cogeneration, the task is not insurmountable.

For example, for an 11 MW steam turbine to be run at 80% capacity factor, the Governor's Commission reports $450/kw capital cost, 0.1¢/kwh O & M, and a heat rate of 4417 BTU/kwh. For steam turbines in general, Power Engineering estimates 5000 BTU/kwh and $500-$600/kw. The capacity factor must be adjusted somewhat, however.

A marginal heat rate for conventional steam plants of around 10,000-11,000 BTU/kwh implies that the cogenerator would use only 40-50% as much fuel as conventional plants to produce a kwh. Stated differently, for every kwh a conventional plant produces, the cogenerator can create 2 to 2.5, essentially getting 1 to 1.5 free kwh's for each kwh produced at conventional heat rates. Therefore, an 80% cogeneration capacity factor can be interpreted as 32% to 40% capacity factor at conventional heat rates and 40%-48% capacity factor at a free heat rate. In order to eliminate the price of oil from the cost of cogeneration, we count only the capacity factor from the "free" generation, net of equivalent conventional oil generation.

In Table 22, we present the cost of cogenerated electricity under various assumptions regarding capital cost and heat rate. The highest capital cost, $600/kw, appears to refer to smaller plants, on the order of 3 MW, but it is included for comprehensiveness. The kwhs generated at the conventional heat rate are assumed to cost about as much as conventional running costs; of course, there are additional savings compared to the fraction of marginal generation which burns #2 oil, and there may be lower losses, since the cogenerator will almost certainly be located close to the load it serves, including the facilities which use its heat, so this assumption is conservative.

Escalating these costs 88% to 1985 dollars (assuming slightly higher inflation than in the nuclear cost estimates), gives costs of 3.8¢ to 6.0¢/kwh. Since only the O & M fraction of the cost escalates after the plant goes on line, this cost is quite stable over time, so long as oil is the marginal fuel for New England, rising only about .5¢/kwh to the year 2000.

Even under the worst-case assumptions, this installation would provide electricity for much lower cost than would Seabrook. In addition, its small size, high reliability, and dispersed siting would give the cogenerator a much greater contribution to reliability than a similar amount of nuclear capacity; the dispersed siting will actually provide improved local reliability regardless of the amount of total generation available in New England.

To the extent that cheaper, non-oil fuels (coal, wood, waste) can be utilized in the cogenerator, the costs can be even lower, depending on the additional costs of handling the fuel and its by-products.

	Heat Rate as Fraction of Conventional Heat Rate	
Capital Cost $/kw	50%	40%
450	2.4¢/kwh	2.0¢/kwh
500	2.7¢/kwh	2.2¢/kwh
600	3.2¢/kwh	2.7¢/kwh

Table 22: Costs of Cogenerated Power, N~~o~~et of Power Generated at Conventional Running Cost

Assumptions:
80% capacity factor
18% carrying charge
0.1¢/kwh O & M

Q: Is the applicants' pessimism regarding solar space heating and water widely shared?

A: Several studies which were not conducted by utilities have concluded that solar thermal energy is now competitive with electricity, or soon will be. For example, the President's Domestic Policy Review of Solar Energy (February, 1979) concluded that solar water heating will be cheaper than electricity by 1985, and that passive space heating already is cheaper. The cost of electricity used in the study is considerably less than the delivered cost of Seabrook power, as calculated above, while the estimated 1985 cost of solar water heating converts to less than 4.1¢/kwh for the Northeast, that of active solar space heat converts to 4.1-5.5¢/kwh nationally, and that of solar cooling to 5.5-6.8¢/kwh nationally.

These conclusions are supported, at least qualitatively, by an NSF study (Solar Heating and Cooling: An Economic Assessment, McGarity, A. F., 1975), an ERDA study (An Economic Analysis of Solar Water and Space Heating, DSE-2322-1, November, 1976), and an OTS study (Application of Solar Technology to Today's Energy Needs, June, 1978).

In fact, even the NEES report, on which Mr. Gmeiner's negative assessment of solar is based, indicates costs to the home owner of 5.6¢ to 8.3¢/kwh saved, depending on the type of system, on whether tax incentives are counted, and on the exact distribution of the better systems. These figures are based on 1976 technology.

Q: Is Mr. Gmeiner's cost estimate of wood-fired generation consistent with his source?

A: No. Mr. Gmeiner (in Exh. M-39) uses higher capital costs and lower capacity factors than does his source (in Exh. AG-178). Using his source's costs, 8% inflation (to be consistent with our nuclear cost calculations - Mr. Gmeiner uses 7%), and Mr. Gmeiner's other assumptions yields 1985 costs of

carrying charges (\$30,700 ÷ 23.1) x .1917
= \$254.77/kw-yr. ÷ (8760 x .85) x 1.08^2= 39.9 m/kwh

O & M, A & G \$1001.5 ÷ (8760 x 23.1 x .85) x 1.08^2 = 6.8 m/kwh

Fuel \$1.39/MMBTU x 1.1^4 x 1.08^2
= \$2.37/MMBTU in 1985
x 13800 BTU/kwh = = 32.8 m/kwh

Total 79.5 m/kwh

Furthermore, burning wood (or similar industrial or commercial wastes) in existing plants (such as Somerset) which were designed to burn coal would involve little additional capital cost; Mr. Gmeiner's estimates would yield an operating cost of about 4¢/kwh for such plants.

In addition, Mr. Gmeiner's analysis does not recognize the value of the waste heat rejected by the wood burning plant. If a new biomass-fired plant were to be built in EUA's service territory, it would make very good sense to locate it near one or more large users of steam or hot water, so that a much larger fraction of the fuel's heat content can be utilized. This strategy would improve the economics of the plant considerably.

Q: Has Montaup presented analysis of the economics of converting some of the Somerset capacity to coal firing?

A: Yes. In D.P.U. 19738, Montaup provided a study performed for EAU by Stone and Webster (S & W) in 1976, apparently to rebut an EPA finding that Units 5 and 6 could be converted. This study makes a number of assumptions which are clearly incorrect now, many of which were also incorrect then.

S & W assumes that the coal-fired Somerset units would be operated as peaking or intermediate units, as the existing oil-fired units are. Therefore, S & W uses capacity factors of 17.5% to 42.3% (for units 5 and 6 respectively) in its analysis. Since the converted plants would have some of the lowest energy costs in NEPOOL (that is, after all, the primary purpose of coal conversion), they would actually be base-loaded, with their capacity factors constrained only by their availability. For these small plants, those capacity factors might be expected to be in the 60% to 80% range, depending largely on the reliability of the scrubber system. Therefore, the fixed operating costs and capital-recovery costs would be spread over about twice as many kwh as the study suggests, and each kwh would be correspondingly cheaper.

The capacities of Somerset 5 and 6 are listed as 59MW and 118MW in the study. Unit ~~5~~ 6 is currently listed as 125MW, and Unit 5 is expected to produce 74MW with its new turbine. Again, this correction indicates that the units would produce more kwh's, so the conversion cost per kwh would be lower.

When the study was performed #6 oil was estimated to cost $1.7792/MMBTU. The price at the Somerset plants had already reached $2.945 last September, and can be expected to increase, at least at the rate of inflation; Mr. Gmeiner expects oil to rise very rapidly in price, perhaps becoming unavailable in the 1980's. Obviously, the higher the price of oil, the greater the value of each kwh of coal-fired generation, each of which replaces a kwh of oil-fired generation, either from Somerset or elsewhere.

S & W was somewhat ambivalent as to whether oil savings were even real benefits from the conversion. The reasoning seemed to be that, since the fuel-adjustment charge allows fuel costs to flow through to the *customers*, only capital and operating costs were incurred by *Montaup*, which S & W perceived to be the client. This is clearly a specious argument; even Mr. Gmeiner does not seem to believe it, since much of his argument for purchasing shares of Seabrook appears to rest on the desirability of replacing expensive oil with "cheap" nuclear capital.

The S & W study also appears to double count some costs. For example, the steam and electricity necessary to operate the scrubber are subtracted from Somerset's output (reducing capacity and increasing heat rate) and also added in to operating costs as though they were purchased from an outside source.

S & W indicate that the scrubbers and auxilaries would occupy 40,000 sq. ft., and would have to be located in an area now occupied by warehouses; this seems to be considered a problem. However, the imminent retirement of Units 1 through 4 appears to make well over 40,000 sq. ft. available, immediately adjacent to the boiler area, without displacing the warehouses (see AGIR M-112). This may reduce the costs S & W anticipates for ducting, supports, chimneys, and blowers, and totally avoid the replacement of the warehouses.

The study assumes that Somerset 5 will be retired in 1987 and Somerset 6 in 1990; Montaup is apparently no longer planning to retire the units so soon. The longer the plant is on line, the better the economics of conversion.

Finally, the Brayton Point plant (also in the town of Somerset) has recently received permission to burn coal without scrubbers; hence, scrubbers may not be needed for Somerset, which would greatly improve the economics of conversion.

Q: What is the result of correcting the S & W study for the factors you have identified?

A: Coal conversion appears to be economically justified for these units, although a more detailed engineering study is clearly necessary.

APPENDIX A: INTERIM REPLACEMENTS AND O & M

The attached tables give O & M and Interim Replacements, by year, from FPC forms and CLP's response to Question CL-5. Current dollar values were converted to 100's of 19~~76~~67 dollars by the following CPI values:

1967	100.0
1968	104.2
1969	109.8
1970	116.3
1971	121.3
1972	125.3
1973	133.1
1974	147.7
1975	161.2
1976	170.5
1977	181.5
1978	195.5
1979	217.4

Average discounted replacements for each ~~limit~~ unit was divided by unit capacity (MW DER) to derive a $/MW figure.

Plant	DER	Average 1967 $/MW
Massachusetts Yankee	175	3544
Vermont Yankee	514	5704
Connecticut	575	3769
Maine Yankee	825	2750
Millstone I	660	5306
Millstone II	870	10019
Pilgrim	655	5440
Average		5223

The average is equivalent to $9480/MW in 1977 dollars.

The summation over time (1985 - 2000, 2000 - 2013) was performed with the formula

$$\sum_{i=1}^{n} ba^{n-1} = \frac{b\ (a^{n}-1)}{a-1}$$

where b is the first year cost
n is the number of years
a is the inflation rate

Details of the Pilgrim projection, which separates out annual refueling expenses, are explained in Technical Appendix 3, Joint Testimony of Paul L. Chernick and Susan Geller on Behalf of the Attorney General in the Boston Edison Time-of-Use Rate Case, D.P.U. 19845.

Yankee Atomic (Massachusetts)

Year	Operation & Maintenance	Discounted O & M	Annual Interim Replacement	Discounted Replacement
1968	$ 1,501,634	14411.07		
1969	1,601,341	14584.16	69-68 $ 51,205	466.35
1970	1,558,120	13397.42	70-69 13,046	112.175
1971	1,744,720	14383.51	71-70 634,441	5230.35
1972	2,911,698	23237.81	72-71 1,229,716	9814.17
1973	2,436,594	18306.49	73-72 1,006,041	7558.54
1974	3,949,709	26741.43	74-73 1,966,958	13,317.25
1975	4,556,747	28267.66	75-74 1,627,434	10,095.74
1976	4,975,628	29182.57	76-75 464,902	2726.70
1977	6,965,560	38377.74	77-76 1,765,929	9729.64
1978	7,652,568	39143.57	78-77 579,991	2966.705

1979 10,158,970

AVERAGE 6201.76

Connecticut Yankee

Year	Operation & Maintenance	Discounted O & M	Annual Interim Replacement	Discounted Replacement
1968	901,000	8646.83	-	-
1969	910,000	8287.795	$ 156,134	1421.985
1970	2,406,000	20687.88	1,955,294	16,812.50
1971	1,910,000	15746.08	290,152	2392.01
1972	2,218,000	17701.52	150,617	1202.05
1973	3,263,000	24515.40	224,045	1683.28
1974	2,684,000	18171.97	12,207,957	82,653.74
1975	4,693,000	29112.90	2,730,463	16,938.36
1976	4,729,000	27736.07	9,586,346	56,224.90
1977	4,761,000	26231.40	2,818,466	15,528.74
1978	4,488,000	22956.52	4,273,396	21,858.80
			AVERAGE	21,671.64

Vermont Yankee

Year	Operation & Maintenance	Discounted O & M	Annual Interim Replacement	Discounted Replacement
1972	414,094	3304.82		
1973	4,956,882	37241.79	73-72 12,439,096	93,456.77
1974	5,691,493	38534.14	74-73 676,472	4580.04
1975	7,682,285	47656.85	75-74 581,248	3605.76
1976	7,912,501	46407.63	76-75 8,147,235	47,784.37
1977	9,775,489	53859.44	77-76 2,493,531 (1)	13,738.05
1978	11,190,721	57241.54	78-77 2,493,531 (1)	12,754.06

AVERAGE 29,320.00

Maine Yankee

Year	Operation & Maintenance	Discounted O & M	Annual Interim Replacement	Discounted Replacement
1973	4,033,909	30307.355		
1974	5,232,497	35426.52	74-73 1,848,741	12,516.865
1975	6,301,628	39,091.985	75-74 12,636,280	78,388.83
1976	5,260,694	30854.51	76-75 1,358,980	7970.56
1977	8,418,474	46382.78	77-76 1,384,393	7627.51
1978	10,817,049	55330.17	78-77 1,356,670	6939.49
			AVERAGE	22,688.65

Millstone 1

Year	Operation & Maintenance	Discounted O & M	Annual Interim Replacement	Discounted Replacement
1971	2,341,000	19299.256	1,374,975	11,335.325
1972	6,280,000	50119.71	590,138	4,709.80
1973	4,918,000	36949.66	3,009,757	23,288.93
1974	7,031,000	47603.25	(417,158)	(2824.36)
1975	9,274,000	57531.02	1,244,794	7722.05
1976	14,665,000	86011.73	23,917,491	140,278.54
1977	12,641,000	69647.38	2,818,466	15,528.74
1978	18,895,000	96649.62	15,667,875	80,142.58
1979	23054982			
			AVERAGE	35,022.70

Millstone 2

Year	Operation & Maintenance	Discounted O & M	Annual Interim Replacement	Discounted Replacement
1976	11,887,000	69718.47507	9,087,209	53,297.41
1977	17,960,000	98953.17	24,434,860	134,627.33
1978	24,759,000	126644.50	14,385,311	73,582.15

1979 21 929 668

AVERAGE 87,168.98

PILGRIM I

Year	Operation and Maintenance	Discounted O+M (100$ 1967)	Interim Replacements (1000$)	Discounted Replacements
1973	4,797	36,040		
1974	7,271	44,230		
1975	7,341	45,540	482	299
1976	12,576	73,760	4,976	2,918
1977	12,765	70,330	16,139	8,892
1978	14,186	73,430	4,189	2,143
			Average:	3,563

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

BEFORE THE ATOMIC SAFETY AND LICENSING BOARD

In the Matter of)
BOSTON EDISON COMPANY, et al.,) Docket No. 50-471
Pilgrim Nuclear Generating)
Station, Unit 2)

JOINT TESTIMONY OF PAUL L. CHERNICK AND SUSAN C. GELLER ON BEHALF OF THE COMMONWEALTH OF MASSACHUSETTS

COMMONWEALTH OF MASSACHUSETTS

BY: FRANCIS X. BELLOTTI
ATTORNEY GENERAL

Michael B. Meyer
Assistant Attorney General
Utilities Division
Public Protection Bureau
Office of the Massachusetts
Attorney General
One Ashburton Place, 19th Floor
Boston, Massachusetts 02108
(617) 727-9714

June 29, 1979

II. THE NEPOOL MODEL

Q: What materials have you reviewed in preparing this portion of your testimony?

A: Until recently, we had available only the Report on a Model for Long-Range Forecasting of Electric Energy and Demand to the New England Power Pool by NEPOOL Load Forecasting Task Force and Battelle-Columbus (6/30/77), hereinafter referred to as "the Report". Our requests for further information, both through the EUA forecast case (EFSC 78-33) and through an ongoing investigation into Boston Edison's construction program (DPU 19494/Phase II) had been unsuccessful.

In the latter case, we recently received, through cross-examination of Mr. Bourcier, copies of partial output from the runs of the model which produced the NEPOOL forecast, forty five "Model Documentations" which revise and supplement the Report, and other information which Mr. Bourcier supplied orally. As of the time this testimony was written, no response to our discovery on BECO in this case had been received.

Q: Do you have any special reservations about reviewing the NEPOOL model based on the documentation available to you?

A: Yes. Both the Report and the Documentation raise almost as many questions as they answer, due to the nature and style of the documents:

1. Many relationships are estimated from data which are not provided. In many cases, the exclusion of the data is understandable, considering its bulk, but makes discovery even more important than in relatively self-contained forecasts.

2. Selected functional forms are presented, without the rejected alternatives, a discussion of the criteria for choice, or goodness-of-fit measures.

3. Some important inputs are user specified, and are therefore not presented in the Report.

4. At this writing, only partial results of the Model are available. Such important intermediate results as sales by end use, appliance penetrations, appliance saturations, labor force participation rates, and value added have not been reported.

5. Several important sources on which the model is based are unpublished NEPOOL/Battelle products, testimony in other cases, comments made in panel discussions at industry conferences, and the like. Considering the sophistication of the NEPOOL model, these omissions prevent any thorough review of the model.

Q: Please describe the structure of the model.

A: Conceptually, the NEPOOL model is divided into seven major sections:

1. The demographic submodule, in which population, migration, and labor force participation are determined;

2. The employment submodule, in which employment by industry type is determined;

3. An interface between the economic/demographic module and the power module, which sets household number, housing type mix, and income distribution;

4. The residential power submodule, which determines appliance saturations and average use patterns;

5. The industrial power submodule which determines value added and KWH/$ value added for each SIC;

6. The commercial power submodule, which determines base load consumption per employee, saturation of electric space heating and cooling, and weather sensitive load for each commercial category; and

7. The miscellaneous power submodule, which forecasts such uses as street lighting, agriculture, mining, railroads, utility use, and losses.

We will attempt to review briefly a sampling of the deficiencies in each section.

Q: Please discuss the deficiencies in the demographic submodule.

A: The migration equations have some serious flaws. Migration rates are postulated as a linear function of the differential between local and national unemployment. Rather than estimating these relationships over time for each state, NEPOOL estimates <u>across</u> the New England states for the period 1960 to 1970. What is really being measured, then, is the attractiveness of Massachusetts, or Vermont, relative to the rest of the country in the 1960's, rather than the effects of changing unemployment rates. This "cross-sectional fallacy" can be quite dangerous; Figure I illustrates how even the sign of the cross-sectional relationship can be different from that of the relationship which holds for each state. Furthermore, due to the nature of the estimation procedure, neither national unemployment nor time-dependent changes can directly effect the migration rate.

Other problems appear in the migration section. NEPOOL admits that wages influence migration, but wages do not appear as a variable in forecasting migration. Similarly, NEPOOL recognizes that schooling influences migration, yet no attempt was made to identify the impact of expansion of higher education in Massachusetts in the 1960's, which certainly attracted more out of state students in 1970 than a decade earlier. No significance tests are offered for the equations; it is not clear that the relations are not simply artifacts of chance. The statistical tests which are provided by NEPOOL indicate that much of the variation in the data is not explained by the equations. Finally, NEPOOL corrects the equation for young males to take out the effects of the military draft in 1970; it does not appear that the countervailing effect of either the Cold War military activity of 1960 or the function of colleges for draft avoidance in 1970 was similarly factored out.

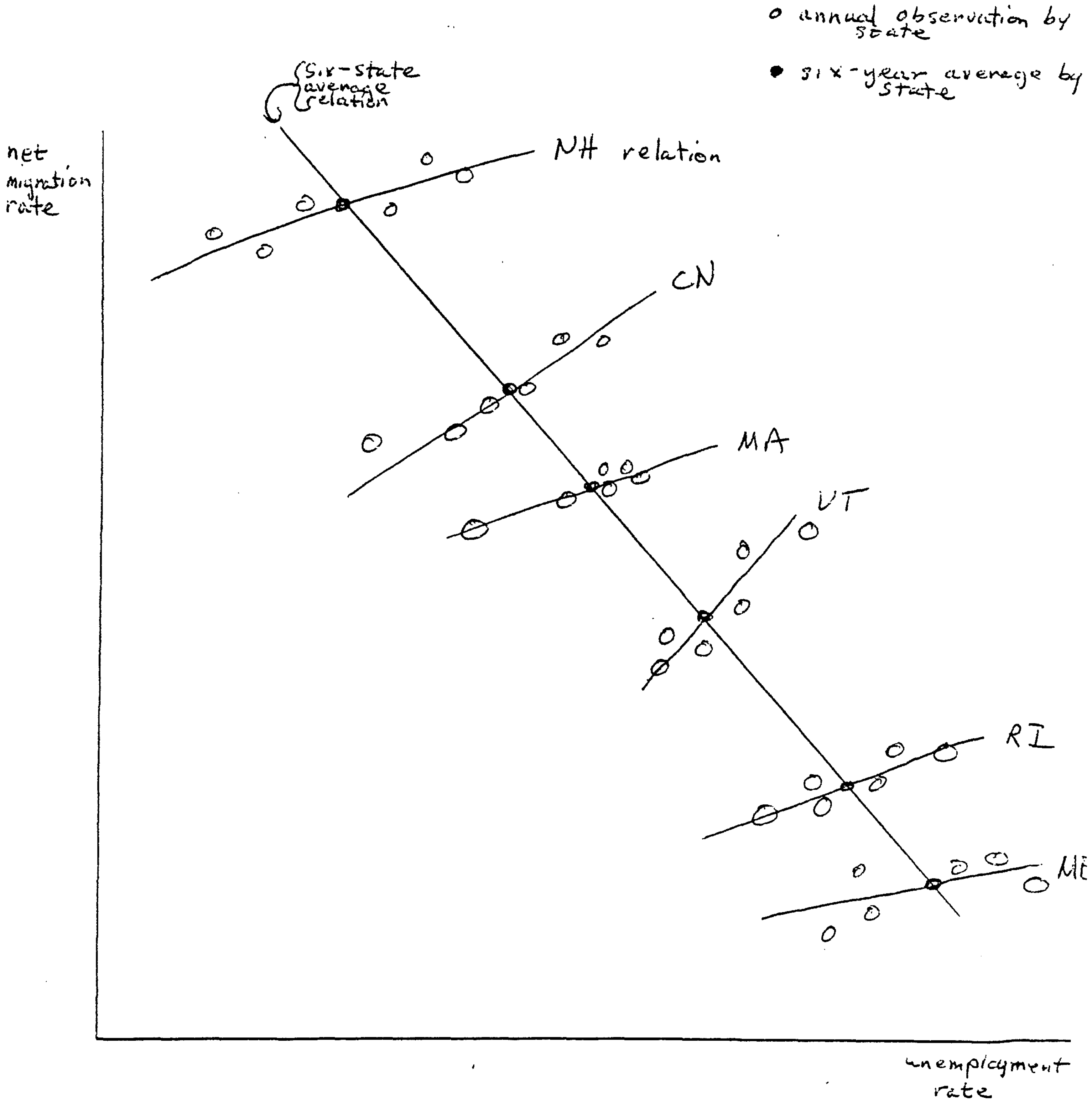


Figure I: Example of the Cross-sectional Fallacy

The sensitivity analyses performed on the migration equations are ambiguously explained in the Report. It is unclear whether the slope coefficients were changed in absolute value or actual level; whether the intercepts, the means, or some other point was held constant when the slopes were increased; and what NEPOOL actually did when it "dropped the error term". In any case, the equations have been revised but no new sensitivity tests were reported.

Q: Do similar errors occur in the estimation of labor force participation rates?

A: Yes. This rate (LFPR) is estimated for each age/sex group as a linear function of jobs per capita and/or of time. Even though data from the years 1960 and 1970 are used, the presence of the time variable probably results in the jobs per capita variable capturing primarily differences between states, just as the migration equations do. For various cohorts, one or both variables are omitted; no reasons are offered for these differences. Finally, having gone to the trouble of estimating some approximation of New England labor forces participation functions, NEPOOL tacks on two time trends based on national projections. It seems that the application of these trends either double counts the effects NEPOOL has attempted to measure directly or eliminates the need for the direct estimation process. In short, it is impossible to determine from the documentation how NEPOOL's LFPR equations were really derived and whether that derivation is reasonable.

Q: How is employment forecasted by NEPOOL?

A: Non-manufacturing employment is forecast as a ratio to state population. Manufacturing employment is forecasted by multiplying exogenous forecasts of national employment growth rates (by SIC) by a "cost index multiplier" to account for differences in local and national costs.

Q: Is the non-manufacturing employment growth forecast reasonable?

A: No. It has two serious problems. First, NEPOOL assumes that all non-manufacturing employment serves local population; in fact, much non-manufacturing employment may be serving businesses and/or serving customers outside the state (e.g., Massachusetts' hospitals and universities, Connecticut's insurance firms, and considerable portions of various states' agriculture and tourism). Second, NEPOOL is apparently projecting non-manufacturing employment per capita in each sector in each state to grow at national rates, despite historic tendencies, in several cases, to grow more slowly and fall more rapidly than the national average. Unfortunately, NEPOOL's documentation on this point is so vague that it is not possible to determine exactly how this projection is performed.

Q: What comments do you have on the cost index multiplier for manufacturing employment?

A: First, NEPOOL's equations imply the relationships listed in Table I infra. For example, if national growth is negative and costs are much lower locally, then the faster national employment falls, the faster local employment grows. This relationship is definitely counter-intuitive.

In addition, NEPOOL provides no documentation for the three complex cost index multiplier curves which it uses for various states. The multipliers often produce worse backcasts than the national growth rates alone.

Q: Are the cost comparisons on which the cost index multipliers operate performed in a reasonable manner?

A: Each SIC's costs are divided into fractions for labor, transportation, taxes, energy and others. For each fraction, a local-to-national cost ratio is derived. Problems arise in all five areas.

With respect to labor costs (RLC), the major problems arise with respect to an equation which adjusts RLC as a function of local

TABLE I

Local to National Cost Ratio	Relationship between Local Growth and National Growth if $NG > 0$	$NG < 0$
over 1.08	$LG = -.1NG$	$LG = 2.1NG$
1.07 to 1.08	$LG = 0$	$LG = 2NG$
.92 to .93	$LG = 2NG$	$LG = 0$
under .92	$LG = 2.1NG$	$LG = -.1NG$

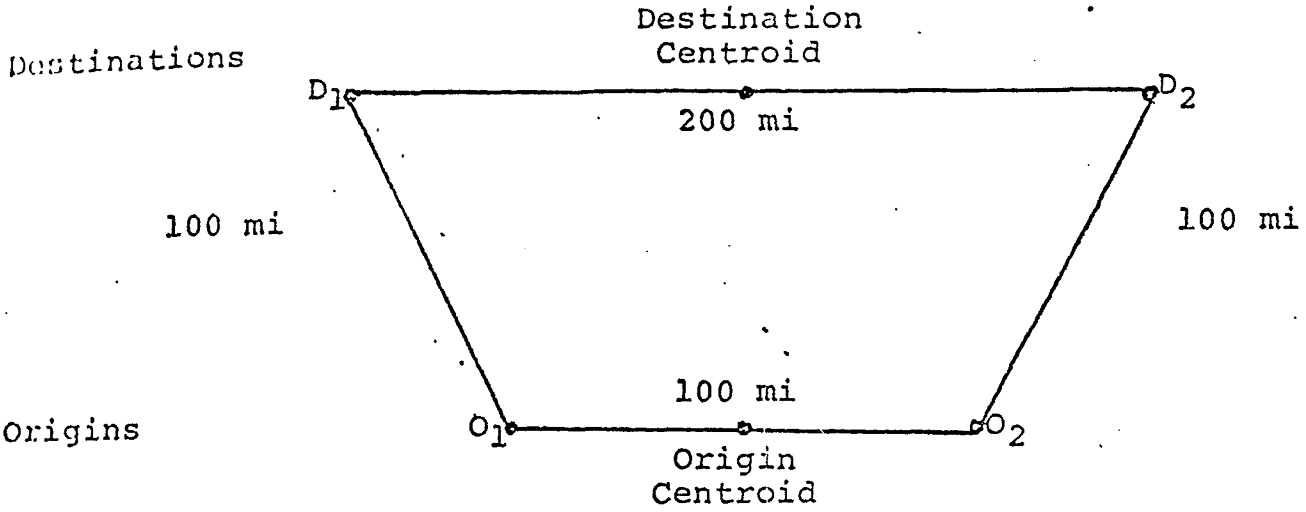
and national unemployment rates. There is no documentation of this equation, and NEPOOL has apparently never tested it. Yet this equation will adjust labor costs downward in the forecast period. Furthermore, NEPOOL adjusts RLC more rapidly when RLC $<$ 1 (local costs are cheaper than national costs) than when RLC $>$ 1. NEPOOL's reasoning on this matter is opaque.

With respect to transportation costs, the major problems concern measurement of distances. While the measurements of distance from New England to other regions are somewhat crude, the real problem arises within New England. NEPOOL assumes that all shipments from any part of a state originate at the state employment centroid and terminate at the New England employment centroid. This will tend to underestimate transportation costs within New England, as illustrated in Figure II, infra.

Q: Are taxes measured better than transportation costs?

A: No, they are very poorly measured. Utility taxes, which probably affect few industrial customers directly, are included in the measure, as are insurance taxes, only a portion of which are paid by manufacturing firms. But real estate taxes, which may be very important costs, are excluded. It may not be possible to accurately measure tax costs to business; it is not clear that a bad measure is more useful than none.

FIGURE II



SUPPOSE:

Shipments originate equally from 0_1 and 0_2
Shipments from each origin are equally divided between D_1 and D_2

THEN:

Average shipment length = 1/2 x 100mi + 1/2 x $\sqrt{3}$ x 100mi = 136.6m.

BUT:

Distance between centroids = $\sqrt{\frac{3}{2}}$ x 100mi = 86.6mi.

Figure II: Why centroids are poor measures of distance when regions are close together.

Q: What about energy costs?

A: NEPOOL uses the 1971 ratio of local electric prices to national electric prices. This was an unusually good year for New England electric prices. It would appear to be more appropriate to use at least the weighted average of 1970 to 1975, which will be somewhat higher, or to use more recent data and trends. In addition, both electric and other energy costs may rise faster in New England, due to oil prices. No change in the ratio is forecast.

Q: If NEPOOL could correct the problems you have outlined, would their cost index methodology be adequate:

[illegible]

A: I think not. First of all, the "Other Cost" category contains between 58.2% and 90.2% of each SIC's costs. Assuming that the four disaggregated cost categories could be carefully measured and forecast and that a reasonable growth modifier function could be formulated, the exercise is pretty pointless if most costs evade both measurement and projection. Furthermore, NEPOOL's undocumented assumption that "Other Costs" are equal to the national average is suspect; those other costs are for construction, services, raw materials, and the like, which must pay local wages, taxes, fuel costs, and transportation expenses.

Q: Are there any further problems in the economic submodule?

A: There is one potentially quite serious generic problem. NEPOOL does not seem to have maintained consistency of the internal forecast with the exogenous forecast which drives it. It is not clear that projections of LFPR, or man-hours per employee, or productivity, or wage rates, or energy costs in the NEPOOL model are compatible with the values Wharton Economic Forecasting Associates uses. For example, suppose that WEFA is projecting that low rates of labor productivity growth, shorter weeks, low wages, and high energy costs will generate large employment. If NEPOOL then takes that large employment growth and assumes higher wages, cheaper energy, longer weeks, and higher productivity, the demand forecast will be directly inflated by the lack of consistency.

In fact, in some cases NEPOOL's forecasting may be internally inconsistent, as well. For the manufacturing employment forecast, wage rates are projected to fall compared to national levels, while for determining personal income (and residential electric use) they are projected to rise at historic national rates.

Q: Are appliance saturations projected in a reasonable manner in the residential power submodule?

A: Most appliance saturations are forecast as functions of household income; this is generally a good approach, although family size probably should be included for several appliances. However, the saturation functions suffer from several errors:

1. No distinction is drawn between new market penetration and old market conversions or acquisitions; this may be a serious deficiency for central air conditioning and electric ranges.
2. An income relation is improperly used as though it were an appliance price relation.
3. The effects of electric price and service costs on effective appliance price are neglected.
4. NEPOOL assumes that real appliance prices will fall rapidly although the most recent data available indicates that real prices are rising.
5. Prices of electricity and alternative fuels are not incorporated in any way; increasing electric costs may counteract the effects of the falling real price of appliances which NEPOOL incorporates.
6. The saturation functions are applied to appliances for which the measured price and/or income are not particularly relevant to purchase decisions.

For example, electric penetration of the range and dryer markets will primarily respond to relative fuel prices and efficiencies, to space heating fuel, and, for ranges, to performance. Income should not affect fuel choice, and if falling appliance price has any effect, it would be to reduce the slight capital cost advantage some electric versions enjoy over their gas counterparts. Furthermore, NEPOOL assumes, without any supporting data or analysis, and often in contradiction to available evidence, very high penetrations of dishwashers and room air conditioners in new construction; increases in total refrigerators saturation; accelerated increases in the ratio of frost-free to standard refrigerators; and constant shares of controlled waterheating.

Electric space heating penetrations are forecast by use of an equation that incorporates electric and oil heating capital and operating costs, promotion by the utility, fraction of housing that is single family, and degree of urbanization. Unfortunately, NEPOOL's model incorrectly measures fuel costs (both in the estimation of the model and in forecasting) and some capital costs, inadequately models the advantage of gas heat over oil heat, explains very little of the observed variation in data, ignores demolitions (which inflate penetration rates) and is improperly adjusted by state. For example, the equation was estimated on the basis of data from thirty-two utilities around the country; since heat pumps are very popular in some warm areas, NEPOOL's cost comparisons may be seriously tainted. Problems are also evident in the estimate of alternative fuel cost: gas is not even considered as an alternative for New England, and new furnace efficiency is assumed to be constant from 1966 on. NEPOOL also gives no hint of how the variables (most importantly, electric price) are forecast; in the case of electric price, the effect of rate reform and elimination of promotional rates should also be considered.

Q: Are NEPOOL's projections of average annual use per appliance reasonable?

A: Curiously, the Report and Documentations do not provide this information. NEPOOL provides only "connected load" for each appliance, which is multiplied by a fraction, F (which varies over the days of the week, the seasons, the time of day, between appliances, and in some cases with temperature) to determine hourly demand. The annual sum of these F's then determines use per appliance. Even in the absence of this information, however, several shortcomings are evident.

NEPOOL has determined a relationship between family size and the annual use by ranges, refrigerators, dryers and water heaters. But this relationship is only applied to determine 1970 consumption, despite the fact that household size is projected to fall over time. No family size adjustment is calculated for other appliances, nor does family size affect the distribution of housing types, which is held constant. This error inflates space conditioning use.

Electric water heater consumption increases with dishwasher saturation, but does not respond to dishwasher or clothes washer efficiency improvements, which should have a substantial effect on average consumption. Apparently, NEPOOL does not understand the sources of anticipated efficiency improvement.

Average use by refrigerators, freezers, dishwashers, and dryers are projected to increase by as much as 2% annually. These figures are based on trends in the 1960's in California, in a time of falling electric prices. They are simply irrelevant to NEPOOL's forecast for the 1980's. In addition, since dishwasher and dryer efficiency targets are formulated on a per-load basis, these trends may imply that the targets will not be met and that efficiency may actually decline.

NEPOOL does not apply the DOE efficiency standards so that refrigerators and freezers each comply as a class. NEPOOL recognizes separate frost-free and standard versions of both appliances, and projects a greater saturation of frost-free refrigerators (the forecast split for freezers is not specified). It the efficiency improvements are applied to the two versions separately; NEPOOL is implicitly predicting that the entire appliance class will not achieve the DOE standards.

In addition, NEPOOL simply ignores the probable enactment of residential appliance efficiency standards beyond the current DOE targets and the inevitable effects of building code changes on electric use by space conditioning and water heating.

Based on "remarks" and "testimony" by NERA personnel, NEPOOL makes a number of peculiar assumptions. They assumed unrealistically high (up to -1.2) short-run price elasticities for several appliances, and rather low (as low ass -0.5) long-run elasticities for other appliances.

Use by refrigerators, freezers, and televisions is amazingly assumed to exhibit no price elasticity at all. The elasticities were arbitrarily manipulated to yield aggregate residential sales in the calibration period.

Use in the miscellaneous category is predicted with the formula:

$$M = (.067 * t + 1.836) * Y * (.996 +.032\ t) * M70 * C$$

where M = miscellaneous appliance use per household
Y = personal income per household
M70 = miscellaneous use in 1970
t = year-1970
C = constant

The first factor is NEPOOL's perceived time trend for appliance expenditures as a fraction of income in the period 1960-1973, which is extrapolated out indefinitely.

The third factor reflects NEPOOL's projection of falling real appliance prices.

One basic problem with this formulation lies in the assumption that electricity consumption is proportional to appliance expenditures. This is a suspect position; many new appliances will replace older, less efficient versions of the same appliance (as in home sound equipment) or will substitute for other appliances (as in many cooking devices) or will be used only quite infrequently (as many shop and kitchen tools). NEPOOL's assumption is incorrect for another reason. NEPOOL is assuming that a doubling of personal income will result in an immediate doubling in the <u>stock</u>, not just the purchase rate, of appliances. This is equivalent to assuming that the lifetime of appliances is only one year.

In any case, NEPOOL does not offer any demonstration that the hypothesized relationships exist between appliance expenditures, appliance stock, and appliance consumption.

The next problem arises in NEPOOL's assumption that miscellaneous appliance purchases increase as a function of time, rather than as a function of income. Both models may fit well in the historic period (in fact, it is unclear how well NEPOOL's time trend fits the data), and the income explanation has more causal appeal. NEPOOL has also established the time trend using dollars deflated in a normal manner (e.g., by the CPI) and then added a 4.3% growth in appliance sales (due to an assumed falling appliance price) which was already captured in the trend. Again, NEPOOL's failure to document the model precludes adequate review. In any case, NEPOOL's projections of falling appliance prices are improper.

As a result of its triple trending (time, income, and appliance price) miscellaneous appliance use is expected by NEPOOL to increase over three times as fast as overall residential use from 1976 to 1990, per household.

Q: Are there errors in NEPOOL's handling of the interaction of appliances?

A: Yes, in at least two cases. Mr. Bourcier acknowledged one ~~blatant~~ obvious ~~serious~~ error which seriously understates the reduction in range use due to increasing saturation of efficient microwave ovens. In addition, it does not appear that the model projects the net energy savings due to microwave ovens that the Report indicated were appropriate.

The effects of wood stoves on electric space heating use are incorporated for only two states; even in these states, the effects of wood stoves are held constant after 1979.

Q: How does NEPOOL initialize its 1970 appliance consumption figures?

A: NEPOOL found that 1970 residential consumption was overforecast by the model. NEPOOL therefore adjusted downward the average connected loads for most appliances, by a state-specific factor of 3.4% to 22.1%. Miscellaneous use, air conditioning and heating are excluded from the adjustment on the basis that "they were originally N.E. values." In fact, miscellaneous use is based solely on data from Connecticut, the state for which the adjustment is smallest. Large portions of the errors in other states' backcasts may result from differences in miscellaneous consumption from the 200 Connecticut customers from whom the miscellaneous data was extrapolated.

Window air conditioning usage appears to be based on Ohio and Baltimore data and on 1977 estimates by BECO and Northeast Utilities (Documentation 15). None of these sources used any New England consumption data, although New England cooling degree days are considered. Electric heating consumption is based on 169 all-electric homes (perhaps of identical size and vintage) in Amherst, Massachusetts (Report, p. G-17). Perhaps the 22.1% error for Maine results from an overestimate of average heating consumption in that state based solely on the Amherst sample and local weather.

Since it is the unadjusted uses, miscellaneous and space conditioning, which grow fastest in the forecast, NEPOOL's improper exclusion of these uses from the 1970 adjustment increase the overall forecast growth rate.

Q: Is the NEPOOL industrial submodule any better than the residential submodule?

A: No. The same problems in documentation exist, compounded by peculiar formulations, internal contradictions, and outright inaccuracies. There does not appear to be a single measure of goodness-of-fit or significance reported in the entire industrial submodule, for example.

Q: Please describe the industrial submodule.

A: NEPOOL first divides the industrial employment (an output of the economic model) into production and non-production employees. To derive KWH sales, the production employment in each SIC in each state is then multiplied by annual man hours per employee, value added per man hour, and KWH per dollar of value added.

Q: Please describe NEPOOL's forecast of production employment?

A: It seems that rather than model the ratio of production to non-production employees directly, NEPOOL chose to forecast the growth rate in value added per employee for each class and then back out the ratio. This is a roundabout approach, and NEPOOL really does not explain why it is used. Even NEPOOL became confused by this section of the module: on p. H-2 the Report says that the ratio increases if the production productivity growth rate is less than the non-production productivity growth rate (which is true), while on p. H-4 the Report claims th exact opposite. Furthermore, since the non-production employee productivity projections are based on New England data (from unspecified source and years) and the production employee productivity projections are from state data, the data seems to be incommensurate. Finally, NEPOOL's manipulation of the value-added-per-production-employee trending also affects the validity of the ratio.

Q: Please describe NEPOOL's projection of annual man-hours per employee.

A: This factor has been falling since 1970, yet NEPOOL arbitrarily assumes that it started increasing in 1977. In addition, it is not clear whether the national employment forecasts utilized by NEPOOL use the same man-hour assumptions, and whether the data was appropriately selected. On the latter point, NEPOOL indicates that only "selected observations" were used in establishing the hours per employee ratio; it is not clear whether this selection affected other portions of the calibration process. In any case, the sudden increase in man-hours inflates the industrial forecast.

Q: Please describe NEPOOL's forecast of value added per man-hour.

A: NEPOOL uses two models for VAMH. Model 1 is a constant and Model 2 is an exponential growth rate. NEPOOL provides no documentation for their choice of model for each SIC for each state (plus New England and totals). In fact, the New England relationships, to which the states are assumed to converge, are not even provided in the documentation.

Q: How does NEPOOL forecast the ratio of KWH sales per dollar of value added?

A: NEPOOL derived their electric intensity trends for some sort of backcast and calibration procedure, involving the estimation of two trend factors. NEPOOL does not provide:

any rationale for the double trending,

any description of the estimation methodology,

any explanation of the level of aggregation (SIC, state, etc.),

any description of the data, such as its source or comprehensiveness,

any data,

any of the estimated trends, or

any indication of goodness-of-fit or of statistical significance of the equations utilized.

Therefore, only NEPOOL knows what was done and whether the method and results make any sense.

The documentation issue is complicated by NEPOOL's claim that special industry studies for seven SIC's, including self-generation, were performed and "the results of all the studies are reported in self-contained studies available at NEPLAN," (p. H-15 of the Report). It would now appear that these reports are not available, if they exist at all, and that NEPOOL's projections for these SIC's, to the extent they rely on the studies, are also undocumented. Despite the reference to self-generation, it appears that potential industrial cogeneration is generally ignored in the NEPOOL forecast.

Q: Does NEPOOL adjust the industrial sales forecast to reflect electric price?

A: Yes. NERA's undocumented elasticities are applied: most of the SIC's long-run elasticities are assumed to be -0.3, which is very small. Other SIC's are assumed to have short-run elasticities as high as -0.45, which seems excessive.

Therefore, long-run price effects will be very small for all industrial use, and may not even compensate for the price effects in the energy intensity trends, let alone capture the effects of recent and future price increases.

Q: What price effects are captured in the energy intensity trends?

A: Two types of price effects are incorporated in these trends, which should not be included. First, some of the long-term adjustments in equipment and processes to the period of falling energy prices in the 1960's must have continued into the 1970's; thus, some of the effects of falling prices are incorporated in those trends. Second, the short-run price elasticities used in the Model (and the calibration) are certainly too high compared to the long-run elasticity used and probably too high in absolute terms as well. As a result, the short-run impacts of the price increases of the 1970's are exaggerated; to yield accurate backcasts, NEPOOL must have exaggerated the energy intensity growth rates as well. For both these reasons, NEPOOL"s energy intensity forecasts are apt to increase far too rapidly.

Q: Do similar problems arise in the commercial submodule as in the residential and industrial submodules?

A: Yes. The same deficiencies in documentation recur. For example, NEPOOL mentions that commercial sales could have been used to drive the submodule, but does not explain why employment was used instead. Other more specific problems arise as well.

NEPOOL estimates retail trade electric consumption per employee on a data set of 196 customers in Connecticut and Maine. Only a short-run price elasticity is used; the lagged effects of falling electric price are probably captured in the time trend, which is then extrapolated into the forecast. Therefore, the retail trade sales forecast contains an implicit forecast of falling electric prices. Furthermore, the time trend may be inflated by the effects of the gas shortage which occurred during the data gathering period. NEPOOL apparently has not attempted to follow up on this study, to determine whether the trends inferred from 1975 data have persisted. In any case, no significance tests are reported for these crucial equations; there is no indication that the observed time trend is significantly different from no trend or from a negative trend. In fact, the time trend was added late in the estimation process; this is probably because the time trend was not very helpful in explaining energy intensity.

In any case, this poorly documented relation for one sector in two states is extrapolated to all commercial categories in all states. All factors, including the time trend, seasonal usage, air conditioning use, and space heating use, and simply scaled to total sales, with the implicit assumption that construction sites, warehouses, schools and offices all use electricity in the same pattern. This is not plausible.

Q: Is price elasticity handled properly in the commercial sector?

A: No. While the short-run elasticity is reasonable (-.2), the long-run elasticity of -1.0 is somewhat low, as NEPOOL admits. NEPOOL claims that this is appropriate, "since the selection of electricity for heating and cooling is treated separately through the saturation functions." But the heating saturation functions are based on upward time trends from the period 1966-1975, which captures the effects of falling prices, and the air conditioning "trends" are not documented at all. (Furthermore, the saturation rates are not corrected for commercial construction rates, which are probably important determinants). Therefore, the saturation trends should be discarded and the long-run elasticity increased to reflect reality.

Another problem occurs in the commercial air conditioning saturation forecasts. Saturations in 1970 are estimated on the basis of numbers of customers with air conditioning, rather than the number of employees in air conditioned commercial space. Since large commercial customers - large office towers, large stores, shopping malls - are already air conditioned, the fraction of air conditioned space (or employees) probably far exceeds the fraction of air conditioned customers. Therefore, NEPOOL is overestimating the potential for expansion.

Q: Does NEPOOL properly incorporate commercial conservation?

A: No. NEPOOL completely omits any form of mandated conservation, such as revisions in building codes, habitation codes, and lighting levels, temperature limits in space conditioning, and appliance efficiency standards. Some of these measures may impact consumption soon (lighting and temperature levels), while others will gradually improve the efficiency of the building stock. NEPOOL also ignores the potential for commercial cogeneration, which is beginning to be realized by such projects as MASCO.

Q: Are there also problems in the miscellaneous power submodule?

A: Yes. ~~For example, in the street lighting sector, KWH per unit of population is trended at the 1960-1974 growth rate for most states, despite recent declines in usage growth and in some cases, total usage. No goodness-of-fit measure is reported for the Massachusetts function.~~

In the agriculture sector, KWH per farm employee is trended on 1966 to 1974 data, which captures a falling trend in electric price.

Railroad sales, utility company use, and sales for resale are user-specified and therefore not explained in the Report. NEPOOL warns that company use and some railroad use is already included in the commercial forecast; there is no indication of how this double counting would be prevented.

Q: Are there any other problems with the NEPOOL demand forecast which transcend individual submodules?

A: At least two such problems are evident in the forecast. First, NEPOOL uses a rather low electric price forecast which is completely undocumented. Second, NEPOOL completely neglects the possibility of reforms in utility rates and operation, such as the establishment of time-of use rates, marginal cost pricing, fair backup and purchased power rates (for cogenerators and other power producers), load management, and utility conservation programs (e.g., voltage regulation, energy efficiency audits and consulting, changes in conditions of service).

Q: Do the results generated by the NEPOOL model confirm the existence of the problems you have discussed?

A: Yes. The model was calibrated on the 1970-1976 period and therefore generally fits well in that period. However, NEPOOL's backcasts for sales growth in 1976 and 1977 (where available) exceed actual growth for each of the major customer classes. Similarly, the model overforecast growth in total output by 1.4 percentage points in 1976, by 4.1 points in 1977 and 3.3 points in 1978. If the average post-calibration error continues in the NEPOOL forecast, output will rise at 0.4% in the 1978-89 period, to a total of only 86520 GWH in 1989, which is 36% less than the NEPOOL forecast for that year and only about 4.5% larger than 1978 output.

Peak growth rates were also overstated in both 1977 an 1978 by 3.5 percentage points. If this error continues in the rest of the forecast period, peak demand will grow at 0.3%, to a peak of 16019 MW in 1989. With existing capacity (minus scheduled retirements and retirements of all capacity now in deactivated reserve), currently planned purchases, and the capacity now under construction, New England would have a reserve margin of 54% in 1989.

Q: Please summarize the NEPOOL forecast.

A: NEPOOL appears to have created a model with numerous unjustified growth-producing assumptions including most of the factors mentioned above. NEPOOL then utilized high short-run elasticities and large commercial conservation corrections to neutralize this excessive growth in the calibration period. Once the calibration period ends, the model grows much too rapidly. Continuation of the infated trends, coupled with new growth-producing assumptions and errors, will produce inflated forecasts.

Q: Does this conclude your testimony on the NEPOOL demand forecast?

A: Yes.

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF PUBLIC UTILITIES

Re: Boston Edison Company's
Construction Program and
Capacity Needs,
D.P.U. 19494

JOINT TESTIMONY OF PAUL L. CHERNICK AND SUSAN C. GELLER ON BEHALF OF THE ATTORNEY GENERAL

FRANCIS X. BELLOTTI
Attorney General

By: Michael B. Meyer
Assistant Attorney General
Utilities Division
Public Protection Bureau
One Ashburton Place
Boston, Mass. 02108
(617) 727-9714

April 1, 1979

IV. PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE

Q: What materials did you review in preparing this portion of your testimony?

A: I obtained the forecast PSNH prepared late in 1977; this forecast is incorporated in the 1978 NEPOOL Load and Capacity Report. The forecast document consists of:

1. Final Forecast Review (11/2/77), presenting final sales forecast,
2. Residential Forecast (10/7/77), the forecaster's response to top management questions and instructions,
3. Residential Forecast (9/6/77),
4. Industrial Forecast (12/20/77),
5. General Service Forecast and Total Price Sales Forecast (10/12/77),
6. Sales to Other Utilities (10/11/77),
7. Development of Monthly Net Price Output and Winter Prime Peaks for the Period 1977-1978 Thru 1988-1989 12/15/77, which is based on time 1 above and presents the peak forecast used in the 1978 L and C Report,
8. Lost and Unaccounted for MWH (1/1/77), and
9. An untitled memo which includes "Summary of Fuel Price Projections" (10/27/77).

In addition, I reviewed the PSNH Preliminary Sales Forecast of August, 1978, which contains actual 1977 sales and partial 1978 sales.

Q: Do you have any general comments on the PSNH forecasting methodology?

A: Yes. In general PSNH disaggregates sales in considerable detal, to the level of individual appliances, industrial SIC's and commercial divisions. PSNH then generally assumes greatly overstated growth rates based on clearly biased projection techniques to produce a drastically inflated sales forecast.

Q: On what specific aspects of this forecast will you be commenting?

A: This testimony will consist of an overall description of the methodology, followed by specific analysis of the residential customer forecast, the space heating penetration forecast, the appliance consumption projections, the "Industrial" class forecasting methodology, the "General" class forecast methodology, the "Other Utilities" forecast, and the peak demand forecast.

Q: Please describe PSNH's overall methodology?

A: The sales forecast is the sum of:

1. The residential sales forecast which is the product of residential customer number times the summation over appliance type of saturation times average use, plus an "Other Use" category;

2. The industrial forecast, which is the sum of sales to:
    a. nine nonmanufacturing industries, each forecasted as the product of projected KW demand and projected hours use;
    b. thirty eight large manufacturing customers, projected as nonmanufacturing;
    c. a group of 300 smaller manufacturers, held constant in the future; and
    d. new manufacturing customers since 1969, trended as a fraction of total manufacturing sales.
3. The general service forecast, forecast as the product of:
    a. general customer number, projected as a generally declining fraction of residential customer number; and
    b. sales per customer forecast to increase linearly.
4. The street lighting forecast, for which I have seen no documentation;
5. The other government authority forecast, which is the sum of sales to:
    a. the Navy Yard and Pease AFB, held constant at about the last three year's average sales;
    b. University of New Hampshire at Durham, projected at .8%; and

6. Other Utilities, which is the sum of Concord Electric Company's forecast of their purchases and PSNH's forecasts of sales to New Hampshire Electric Cooperative, Exeter and Hampton, Wolfeboro, Ashland, and New Hampton.

A fraction of annual use is then attributed to January. A monthly load factor is applied to the January use to determine annual peak demand.

Q: Please describe the deficiencies in the residential customer forecast?

A: There are major problems in both the population forecast and in the projection of the ratio of customers to population.

Strangely enough, PSNH uses New Hampshire population forecasts, rather than town or county forecasts, despite the fact that much of the state is served by other utilities. Absolutely no attempt seems to have been made to disaggregate the PSNH territory population from the state population in any year. Since the PSNH territory population as a fraction of state population may change in the future in very different ways than it has in the past, this error may seriously distort the PSNH forecast. Furthermore, it is hard to believe that PSNH has been unable to obtain an exogenous state-wide forecast since 1975.

PUBLIC SERVICE CO. OF NEW HAMPSHIRE

Book No. ____ Page No.

Subject: POPULATION FORECAST FOR NEW HAMPSHIRE

File No. ____

Sheet ____ of ____

Computed By ____ Date AUG 31 1977 Checked By ____

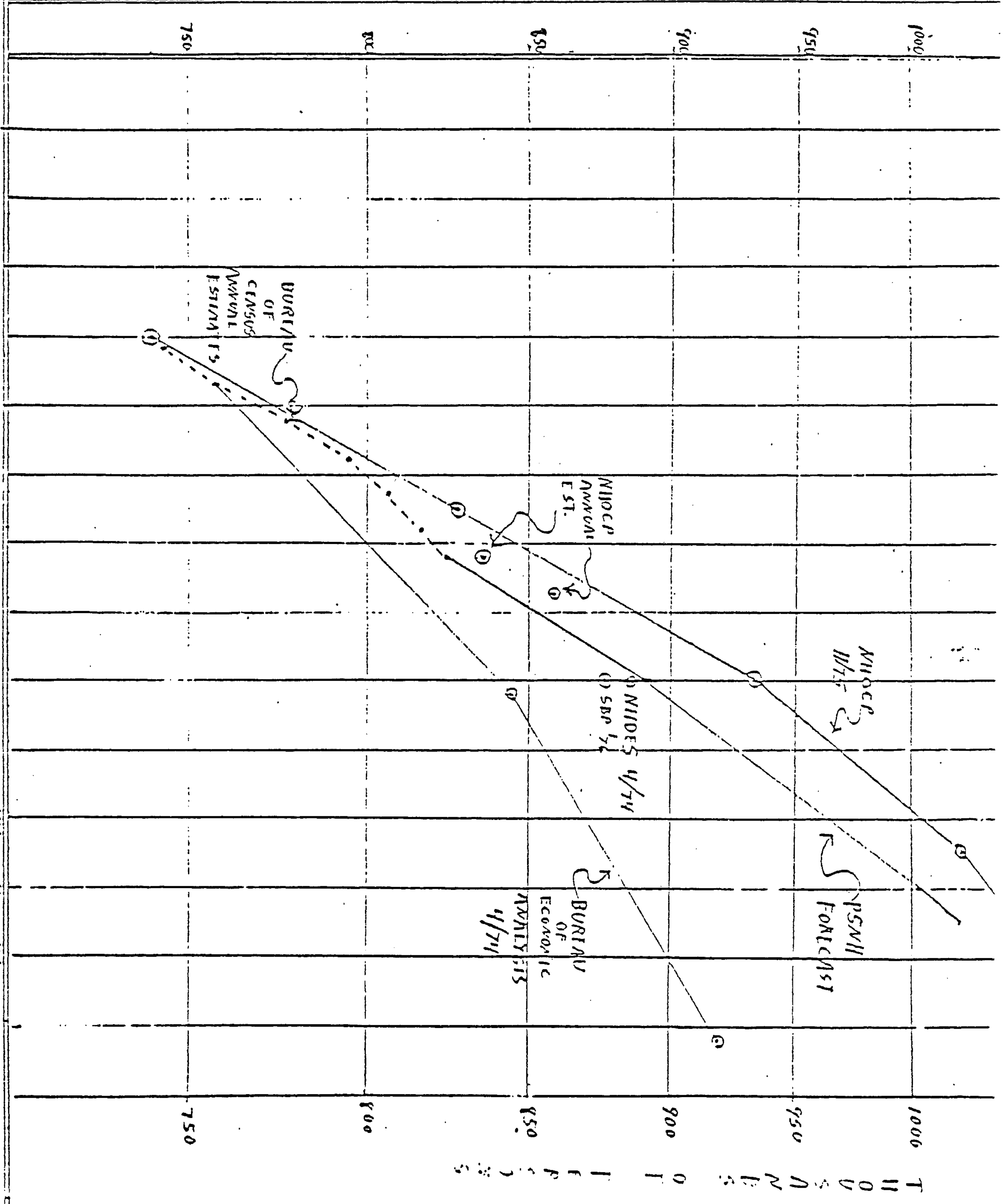


Figure PS-1

Even given the limited data they utilize, PSNH seems to have produced an unrealistic state-wide population forecast. First of all, the claim that the PSNH forecast is conservative, because it lies below the N.H. Office of Comprehensive Planning (NHOCP) estimates for 1976 and 1977, is simply irrelevant. Since the customer forecast is based on trending historical ratios and applying the results to current estimates, the data of interest relates to growth rates: consistent over or under-estimations of population produce consistent changes in customer to population ratios. In setting their customer to population ratio PSNH uses Department of Commerce estimates, so it is imperative that the population forecast be consistent with those figures. Yet, PSNH's population forecast growth rate exceeds the NHOCP forecast growth rate, which has historically exceeded the Federal estimates (and NHOCP's own estimates) in growth rate, as well as absolutely. Given the data presented in figure PS-1 (from PSNH's forecast), their state population forecast growth rates appear grossly overstated, rather than conservative.

Q: How does PSNH forecast residential customer number, given state population?

A: PSNH uses an equation of the form

$$\text{Customers}_t = a\left[\text{Population}_t\right]^b \times \left[\text{Customers}_{t-1}\right]^c$$

where a,b,c are estimated coefficients

t indicates current year

t-1 indicates previous year

The reasoning behind this approach is utterly opaque. Of the obvious causal variables for customer number, only total population is represented: neither age-specific population, per capita income, youth employment rates, nor any measure of PSNH's population as a fraction of the state appears in the equation. Even time, which might serve as a proxy for some relevant variables, is excluded. This formula compounds growth in the customer-to-population ratio, implying that family size will fall faster and faster over time. Actually, as large families are phased out, the ratio should tend to stabilize. (Surely, the trend cannot continue past unity or in PSNH's case, some larger number, reflecting the unspecified share of state population in the service territory). In addition, since b + c = 1.2233, customer number must increase over 20% faster than population; this relationship was estimated on the basis of an annual population growth rate around 1.96%, yet it is extended to a period of forecast 2.44% population growth, a 24.5% higher rate. Since the change being modelled is more dependent on time than on population, this extrapolation from low growth to high growth will be likely to overestimate the customer growth rate, in addition to the errors caused by compounding customer number and by using an excessive population growth rate.

Q: Once PSNH has derived a customer number, how is the rest of the residential forcast derived?

A: PSNH estimates the consumption per customer by forecasting a saturation and an average consumption for each of 14 appliances, to which are added lighting and other uses.

The saturation projections are apparently entirely subjective, sometimes loosely based on historical trends. (See our testimony in D.P.U. 19494, Phase I, on trending saturations.) There is no disaggregation by dwelling type, nor between new market penetrations and acquisitions by existing customers. Apparently, no correction is made in the heating, water heating, range, or dryer categories for the gas shortages of the mid-1970's, which may have artificially increased electric market share. Furthermore, special problems are evident in the space heating and dryer saturation forecasts.

Q: What are those special problems?

A: In the case of electric space heating , a number of new electric space heating customers is forecast, based on PSNH's Marketing Division forecast of additional electrically heated dwellings. PSNH's data indicates that Marketing has historically overestimated by an average of

28.3%. Therefore, the forecast is lower than marketing's projection, but only by 20.8%. This greater confidence in marketing's judgment seems particularly ill-founded considering the caveat that:

> The Marketing Division Forecast is contingent upon an increase in manpower in order to assist people in making their decisions concerning selection of spaceheating systems and energy.

To the extent that the forecast relies on the assumption that the New Hampshire Public Service Commission will allow PSNH to spend ratepayers' money (or even stockholders' money) on promotional advertising and incentive to builders and homeowners, even while such practices are being discouraged or prohibited elsewhere, it seems overstated. In fact, the saturation trends of all appliances for which gas is an alternative energy source would be distorted by that assumption. (In any case, the historic saturations of the other appliances with gas alternatives were inflated by the high electric heating penetrations; if PSNH's forecast trends are based on those inflated past penetrations, they are overstated.)

Curiously, PSNH projects rising heating penetrations until 1984, when Seabrook 2 is scheduled to come on line, and falling slightly thereafter. Regardless of how and why the projection was derived, PSNH is forecasting that the falling trend since 1973 will be reversed, even in the face of rising electric prices, regulatory reforms and improved gas availability.

In the case of dryers, PSNH reports a strong variability in their survey results, which suggests some problems in the sampling or data gathering techniques. However, PSNH says that they simply ignored the low 1973 saturation survey result and "the trend from 1971 to 1976 was extrapolated". But, as Table PS-1 shows, the .92 annual percentage point increase of the 1971-1976 period is increased to a 1.48% annual growth in the 1976-1987 period; the projected rate of increase also rises slightly within the forecast period, from 1.4 to 1.6 percentage points. Therefore, even when PSNH attempts to explain its saturation forecasts, the projection belies the documentation. Additionally, PSNH reports in the text that the 1973 dryer saturation was 40.9%, yet it is reported in the saturation tables as 44.9%; it is not possible to determine how much of the other data, which PSNH presents as "actual", has been similarly altered.

Q: How appropriate are PSNH's forecast of usage per appliance?

A: Average use projections are poorly developed and grossly overstated. In general, all the projections suffer from PSNH's failure to distinguish changes in new dwellings from those in existing dwellings, to distinguish between apartments and single-family homes, to allow for family size effects, or to systematically apply efficiency standards to new units and retrofitting to old units.

In addition, we have specific comments on space heating, water heating, refrigerators, dryers, freezers, televisions, air conditioning, lighting and other use.

Q: Please comment on PSNH's space heating use projection.

A: The space heating use is held constant at the 11000 kwh/yr. estimate for 1975. PSNH acknowledges that future homes will be smaller than current ones and that supplemental heating systems (presumably solar and wood) would decrease usage, yet no such decrease is forecast. PSNH does not seem to realize that future housing stock will almost certainly be better insulated, weather-proofed, situated, and designed than past ones; that apartments use far less heating energy than houses; that the smaller families that PSNH projects will result in longer daily time periods when homes are unoccupied and less heated; that wood and solar heat will have far greater application in future homes than past ones (indeed, electric heat will frequently be the "supplementary" source); or that existing dwellings can be better insulated, weather proofed and equipped with automatic-setback thermostats, wood stoves, and solar heating. Therefore, a sizable decrease of the average space-heating use would appear to be appropriate.

Q: What errors does PSNH make in its forecast of electric water heater use?

A: PSNH forecasts increases in average water heater use, "reflecting the increase in dishwasher and clothes washer saturation being offset by increased efficiency in waterheaters." However, taking into account the efficiency improvements expected in <u>new</u> water heaters, dishwashers and clothes washers, as well as family size, should decrease average waterheater use by over 20% by 1987, resulting in residential sales 5% lower then forecast, even with PSNH's saturation projections. In addition, insulation retrofit on existing heaters and pipes, better placement of water pipes in new construction, and improved basement insulation and flow-reduction devices in all dwellings will further reduce electric use per waterheater. Also, water use by clotheswashers and dishwashers will tend to respond to family size decreases.

Q: What deficiency exists in the refrigerator use forecast?

A: According to PSNH, average refrigerator use was 1592.33 KWH/yr. in 1976. Assuming a 15-year life, some 38% of existing refrigerators will be replaced from 1981 to 1987; also, 19% of PSNH's projected 1987 customers are new since 1980. Therefore, some 57% of PSNH's refrigerators would be covered by federal standards of 28% efficiency improvements, for a net 16% improvement and an average use of 1338 kwh/refrigerator. PSNH forecasts 1934.39 kwh/refrigerator, a difference of about 600kwh/unit or 675 kwh/yr/customer. This is 6.4% of the residential forecast for 1987. According to NEPOOL, another reduction of 40kwh would result from smaller family size.

Q: Do the same effects occur for dryers?

A: Yes. Federal standards of 4% would apply to about two thirds of PSNH dryers, for a 2.8% reduction. In addition, family size charges would produce another 8.8% decrease, for a total effect of 11.4% reduction. PSNH assumes a decrease of only 2.5%.

Q: And for freezers?

A: Freezer average energy consumption is scheduled to decrease 22% for new units, or about 15.4% for PSNH's average unit. PSNH forecasts a decrease from 1146 to 1083 kwh, only a 5.5% decrease.

Q: Does PSNH do better with televisions?

A: No. The federal standards of 35% reductions for color sets and 65% reductions for monochrome sets will probably be exceeded by the average sets 1987, as circuitry advances from transistors to integrated circuits. PSNH forecasts improvements of only 11.2% in color televisions and of only 5.8% in monochrome sets.

Furthermore, as the number of sets per household increases from 1.167 to 1.32, average hours use per set (and kwh/yr) should fall, especially because the number of people per household will be falling.

Q: What comments do you have on window air conditioner average use?

A: PSNH lowers average use by less than 2%, despite federal standards of 22% improvement and improvements in weather proofing in homes.

Q: How does PSNH forecast ~~forecast~~ lighting use?

A: They hold their estimate constant. Efficiency improvements (particularly through greater use of fluorescent bulbs), smaller home size, and smaller family size should all contribute to a decrease in this category.

Q: How does PSNH forecast other use?

A: Other use is basically the residuals in PSNH's estimates of individual appliances saturations and average use, plus such additional uses as microwave ovens, fossil heating auxiliaries, central air conditioning, and small kitchen, personal and entertainment appliances. PSNH apparently regressed this random error term against per capita income and then projected it into the future on a per household basis. The purpose in trending an error term is not quite clear. Beyond its retrospective use as a catch-all, the other use has a legitimate forecasting role, reflecting the use of particular appliances. However, many of these uses should decrease over time, or cause these uses to decrease. For example:

(1) microwave ovens will replace far more energy than they use; PSNH forecasts that 76% of ranges will be electric, so most of the displaced energy will be electric;

(2) fossil heating auxiliaries will decrease in saturation as electric heating saturation increases (PSNH assumption), and decrease in average use as house size falls and weather proofing improves;

(3) central air conditioning is subject to DOE appliance efficiency standards; and

(4) home sound equipment will become more efficient as the conversion continues from tubes to transistors to integrated circuits.

Considering the nature of PSNH's "data" for their trend, and the factors described above, it seems excessive to increase Other Use at over 7% per year.

Q: Does this conclude your testimony on PSNH's residential model?

A: Yes.

Q: Please describe PSNH's basic approach to the Industrial class?

A: PSNH disaggregates the Industrial class (which includes large commercial customers) into a number of categories. For most of those, sales are projected as the product of forecast KW billing demand and forecast hours of use for each category. Each of these forecasts are, at PSNH's discretion, based on a sort of exponential trend analysis, on an historic average of 1970-1976, on a 1973-1976 average, or on some totally fabricated growth rate. Thus, PSNH started with an inadequate trending technique and apparently manipulated the trends to produce any desired result. This "technique" was applied to nine non-manufacturing categories and 78 large industrial firms.

For the industrial firms, PSNH manages to "trend" a .9% historic growth rate into a 3.47% growth rate. This is achieved by breaking the class into three groups.

> Group I: Both KW demand and hours of use showed some increase, however erratic, in the period 1970 to 1976. Sales are forecast as the product of the two trended variables.
>
> Group II: While KW demand generally rose, hours of use generally fell. Hours of use were held constant at 1970-1976 average levels, (not recent ones) while KW demand was trended.
>
> Group III: PSNH simply projected a growth rate from "recent indicators", apparently subjectively.

Various non-manufacturing divisions are trended in a similar variety of ways.

Q: How were the other portions of industrial sales projected?

A: The total sales to 300 small industrial customers is held constant (at a level 6% higher than 1976) in the future, despite the fact that these sales fell in four of the last six years, for an overall decline of 2.5% annually from 1970 to 1976.

Sales to new industrial customers is projected as a fraction of total sales to manufacturing. Since this total includes the new customers, the formula doubly compounds the growth rate. Some time in the year 2020, this relation predicts infinite sales to new customers. In addition, the ratio of new sales to total sales is further increased by two percentage points per year, which, in a sense, approximates the historical experience. But the 1970-1976 experience is equally supportive of a two percentage point annual change in new sales as a fraction of old sales, or of a linear 19.5 GWH per year increase in new sales (which fits with $r^2 = .99$). While PSNH's rather imaginative method produces 657.6 GWH of new sales in 1987 and a 15.08% growth rate from 1977 to 1987, taking new sales as a fraction of old sales yields 432.9 GWH in 1987 and a 10.37% growth rate, while linear growth yields 342.6 GWH and an 8.00% growth rate. Both PSNH's method and the new-as-a-fraction-of-old method described above are greatly inflated by PSNH's projection of much faster future growth in sales to old customers (2.87% from 1976-87) than occurred in the past (.90% from 1970-76).

Q: Does any of the evidence available to you suggest that PSNH utilized reasonable, consistent or appropriate statistical or economic methods in producing their projections?

A: No. The only consistency is that PSNH repeatedly manipulates formulae and data to produce projections which are not supported by their own data.

Q: How does PSNH forecast sales to their General Service customers?

A: PSNH determines the number of General Service customers (apparently small commercial enterprises) by some type of trending of the 1960 to 1976 data for the ratio of General to Residential customers, with a 1987 result of .1113. However, extrapolating the negative compound growth rates of 1960 to 1976 or 1966 to 1976 produces a 1987 ratio of .1067, while the 1972 to 1976 growth rate yields a 1987 ratio of .1007. Some of the discrepancy arises from PSNH's increase of the ratio in 1977 and 1978; not until 1981 does their ratio forecast fall below 1976 actual levels.

Sales per customer is projected to increase linearly at almost six times the average 1973 to 1976 increase. PSNH claims that this growth rate is moderate and reflects conservation, but neither building efficiency standards, future equipment efficiences, nor price elasticity are addressed explicitly.

Thus, General Sales are the product of the inflated Residential customer forecast an oddly high General to Residential customer ratio, and a highly suspect trended use per customer. This results in a greater forecast MWH sales increase to this class, in each year 1978-1987, than in the commercial rebound year of 1976, and greater percentage increases in all those years, except two, than in 1976.

Q: Is the separate projection of General customer number and sales per customer a reasonable approach for this class?

A: Probably not, due to the diversity generally found in the commercial sector.

Q: How are sales to Other Government Authorities forecast?

A: A few large users are held constant or increased slowly, while the rest are increased as a class at 10% year, greater than their 1970 to 1976 growth rate. No accounting seems to be made for any further conservation in this sector.

Q: How were sales to other utilities forecast?

A: From the materials available to us, it appears that the long-term historical trends were subjectively modified for each utility, except for Concord, which forecast its own purchases. For all companies, annual growth in sales increases over time. Apparently, either no conservation was assumed for the customers of these utilities, or a greater share of their purchases are projected to come from PSNH: it is not clear what assumptions are made regarding other sources of supply.

Q: What other factors affect PSNH's peak forecast?

A: PSNH appears to be forecasting a small increase in the fraction of annual sales which occur in January, apparently reflecting the assumption that space-heating usage will continue to rise. However, monthly load factor, which has been steadily increasing since 1974, is held constant at a level lower than the 1975, 1976, or 1977 actual values. Using 1977's January fraction and monthly load factor, 1987 peak would be 7.7% lower than PSNH's forecast, a difference of 168 MW, even using PSNH's forecasts of sales and losses. This calculation does not include the effects of load management (including controlled water heating, which PSNH apparently is promoting), time of use rates, or the generally higher load factors predicted in the industrial sector.

Q: Does this conclude your testimony on PSNH's forecast?

A: Yes.

TABLE PS-1: PSNH DRYER SATURATION FORECAST

	DRYER KS9
70	0.367
71	0.431
72	0.440
73	0.449
74	0.548
75	0.467
76	0.477
77	0.491
78	0.505
79	0.519
80	0.534
81	0.549
82	0.564
83	0.579
84	0.594
85	0.609
86	0.624
87	0.640