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THE COMMONWEALTH OF MASSACHUSETTS
BEFORE THE DEPARTMENT OF PUBLIC UTILITIES

RE: INVESTIGATION OF THE MMWEC FINANCING PLAN FOR SEABROOK UNIT 1	DOCKET No. 1627

TESTIMONY OF PAUL CHERNICK
ON BEHALF OF THE
EXECUTIVE OFFICE OF ENERGY RESOURCES

January 14, 1985

Table of Contents

1 - INTRODUCTION AND QUALIFICATIONS 1
2 - SEABROOK 1 COSTS: NOMINAL DOLLARS AND RATE EFFECTS 9
3 - COMPARING SEABROOK TO ALTERNATIVE POWER SOURCES 15
4 - ALTERNATIVE ENERGY OPTIONS 28

4.1 - Introduction 28
4.2 - Wind 42
4.3 - Hydro 44
4.4 - Wood and Other Biomass 46
4.5 - Solid waste 48
4.6 - Cogeneration 50
4.7 - Hydro Quebec 56
4.8 - Alternatives Summary 57

5 - CONSERVATION 59

5.1 - Conservation Objectives and Program Design 59
5.2 - Insulating the Building Shell 73
5.3 - Other Space Heating Conservation Techniques 80
5.4 - Hot Water Energy Conservation 83
5.5 - Lighting Efficiency Improvements 87
5.6 - Residential Appliance Efficiency 91
5.7 - Rate Design 93
5.8 - Other Conservation Options 101
5.9 - Conclusions and Assessment 105

6 - BIBLIOGRAPHY 107
7 - TABLES AND FIGURES 110
APPENDICES

A - Resume of Paul Chernick
B - Nominal Cost Analysis
C - "Opening the Market to Conservation"
D - "Wind Systems," Vachon & Associates
E - "Hydopower in Massachusetts," Smart
F - "Alternative Fuel Technologies in Massachusetts," Pequod Associates
G - "Technical Assessment Manual," CEC
H - "Cogeneration Potential in Massachusetts," ARS
I - California Program Summaries
J - "Survey of Utility Projects," Blevins

TESTIMONY OF PAUL CHERNICK

ON BEHALF OF THE EXECUTIVE OFFICE

OF ENERGY RESOURCES

1 - INTRODUCTION AND QUALIFICATIONS

Q: Mr. Chernick, would you state your name, occupation and business address?

A: My name is Paul L. Chernick. I am employed as a research associate by Analysis and Inference, Inc., 10 Post Office Square, Suite 970, Boston, Massachusetts.

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

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

I was a Utility Analyst for the Massachusetts Attorney General for over three years, and was involved in numerous aspects of utility rate design, costing, load forecasting, and evaluation of power supply options. My work has considered, among other things, the effects of rate design and cost allocations on conservation, efficiency, and equity; the design of conservation programs; and the establishment of purchased power rates for small power producers and cogenerators; and the comparison of the costs of nuclear power to those of conservation and alternative energy development.

In my current position, I have advised a variety of clients on utility matters. My resume is attached to this testimony as Appendix A.

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

A: Yes. I have testified over thirty-five times on utility issues before this Department and such other agencies as the Massachusetts Energy Facilities Siting Council, the Texas Public Utilities Commission, the Illinois Commerce Commission, the New Mexico Public Service Commission, the District of Columbia Public Service Commission, the New Hampshire Public Utilities Commission, the Connecticut

Department of Public Utility Control, the Michigan Public Service Commission, the Maine Public Utilities Commission, the Pennsylvania Public Utilities Commission, and the Atomic Safety and Licensing Board of the U.S. Nuclear Regulatory Commission. A detailed list of my previous testimony is contained in my resume. Subjects I have testified on include cost allocation, rate design, long range energy and demand forecasts, costs of nuclear power, conservation costs and potential effectiveness, generation system reliability, fuel efficiency standards, and ratemaking for utility production investments and conservation programs.

Q: Do you have a track record of accurate predictions in capacity planning?

A: Several of my criticisms of utility projections have been confirmed by subsequent events or by the utilities themselves. In the late 1970's, I pointed out numerous errors in New England utility load forecasts, including those of Northeast Utilities, Boston Edison, the NEPOOL forecasts, and various smaller utilities, and predicted that growth rates would be lower than the utilities expected. Many of my specific criticisms have been incorporated in subsequent forecasts, load growth has almost universally been lower than the utilities forecast, and my general conclusions have been implicitly accepted by the repeated downward revisions in utility forecasts.

My projections of nuclear power costs have been more recent. However, utility projections have already confirmed many of my projections. For example, in the Pilgrim 2 construction permit proceeding (NRC 50-471), Boston Edison was projecting a cost of $1.895 billion. With techniques similar to those used in this testimony, I projected a cost between $3.40 and $4.93 billion in my testimony of June, 1979. Boston Edison's final cost estimate (issued when Pilgrim 2 was cancelled) stood at $4.0 billion.

In MDPU 20055,[1] PSNH projected in-service dates for Seabrook of about 4/83 and 2/85, at a total cost of $2.8 billion. I predicted in-service dates of 10/85 and 10/87, with a cost around $5.3-$5.8 billion on PSNH's schedule or $7.8 billion on a more realistic schedule. At the time I filed my testimony in NHPUC DE 81-312, PSNH was projecting in-service dates of 2/84 and 5/86, with a total cost of $3.6 billion, while I projected dates of about 3/86 and 6/89, and a cost of about $9.6 billion. Within two months of my filing, PSNH had revised its estimates to values of 12/84, 7/87, and $5.2 billion. On March 1, 1984, PSNH released a new semi-official cost estimate of $9.0 billion, with in-service dates of 7/85

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1. Complete citations for each proceeding in which I have testified are provided in my resume, Appendix A to this testimony.

and 12/90. Thus, PSNH has moved its in-service date estimates, and increased its cost estimates, substantially towards my projections.

In MDPU 20055 and again in MDPU 20248, I criticized PSNH's failure to recognize capital additions (increase in plant investment during the operating life), its error in ignoring real escalation in O & M, and its wildly unrealistic estimate of an 80% mature capacity factor (even the Massachusetts utilities seeking to purchase Seabrook shares were more realistic about capacity factors). I suggested capital additions[2] of $9.48/kW-yr., annual O & M increases of $1.5 million/unit (both in 1977 $) and 60% capacity factors. Since about 1982, PSNH has projected capital additions, escalated real O & M at about 1% (about $0.1 million per unit annually), and projected a somewhat more reasonable mature capacity factor of 72%. Thus, PSNH has implicitly accepted my criticisms, even though the O & M escalation and capacity factor projections are still very optimistic. While my original analyses (and the studies I relied on) were based on data only through 1978, experience in 1979-81 confirms the patterns of large capital additions, rapid O & M escalation, and low capacity factors. The 60% capacity factor figure, in

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2. To the best of my knowledge, this was the first quantitative analysis of actual capital additions to nuclear plants.

particular, has been widely accepted by regulators (such as the California Energy Commission) and even utilities (such as Commonwealth Edison and now Central Maine Power[3]).

Critiquing and improving on utility load forecasts and nuclear power cost projections has not been very difficult over the last few years. Many other analysts have also noticed that various of these utility projections were inconsistent with reality.

Q: Have you testified previously on conservation and alternative energy development?

A: Yes. My testimony in DPU 20055, EFSC 79-1, DPU 558, and NHPUC 81-312 all discussed aspects of conservation and alternative energy development. My testimony in DPU 535 addressed the design of PURPA rates for small power producers and cogenerators, and much of my rate design testimony has addressed conservation effects (especially DPU 200 and 243).

Q: Have you authored any publications on conservation and alternative energy development?

A: Yes. My paper, "Opening the Utility Market to Conservation: a Competitive Approach," was presented to the International Association of Energy Economists' convention in November, and

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3. See NERA (1984).

will be published in the conference proceedings. That paper is attached as Appendix C to this testimony.

Q: What is the subject of your testimony?

A: I have been asked by the Executive Office of Energy Resources (EOER) to compare the cost of completing and operating Unit 1 of the Seabrook nuclear power plant to a variety of conservation and supply options for MMWEC and its members. The objective of this comparison is to allow the Department to determine whether, if Seabrook 1 is not completed, MMWEC can use conservation and alternative energy sources to replace its anticipated share of Seabrook power, and to meet its projected capacity requirements, through the end of the century, without further central station construction.

Q: How is your testimony structured?

A: Section 2 derives estimates of the cost to MMWEC of power from Seabrook Unit 1, in millions of nominal dollars, and in cents/kWh, and of the first year rate increase which would result from either the completion or cancelation. Section 3 discusses the comparison of Seabrook costs to the costs of conservation and alternative energy sources. Section 4 derives and reports estimates of the costs and potential of various forms of alternative energy generation. Section 5 derives and reports estimates of the costs and potential of various forms of conservation efforts, and discusses the design of conservation programs.

2 - SEABROOK 1 COSTS: NOMINAL DOLLARS AND RATE EFFECTS

Q: What do the costs and performance you estimated for Seabrook in DPU 84-152 imply for the effect of the unit on rates?

A: There are several important implications. First, Seabrook power would be very expensive. The power would cost 21-34 cents/kWh[4] (depending on whose cost and capacity factor estimates are used) in the first year, rising to 24-35 cents around 2000, and then rising again. The levelized cost of Seabrook power would be 21-32 cents/kWh over the first 15 years; at MMWEC's suggested discount rate of 11%. Second, completing the unit would raise total rates for the MMWEC members and participants by $100-160 million in 1988, resulting in an average rate increase of 39-61% for member participants, with individual utilities' rates rising by as much as 214%. Third, even if Seabrook 1 were cancelled promptly, it would increase rates to MMWEC participants by $78 million in 1988, representing an average 29% increase in rates for member participants, and as much as 100% for some participants. Reductions in sales, and the loss of customers, could result in further rate increases in both the

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4. Except as specifically stated, all costs in this testimony are in nominal dollars.

completion and the cancelation cases.

Q: What is the unit's major benefit to the MMWEC participants?

A: Seabrook 1 is being built almost exclusively for fuel displacement purposes. Like all nuclear units, it will provide lower fuel costs than the oil plants which NEPOOL currently has in abundance.

Q: Have you determined the rate effects of Seabrook 1 as a energy source?

A: I have compared the cost of Seabrook 1 to the cost of the existing oil plants which it would displace in the short run under a variety of assumptions regarding Seabrook 1 cost and reliability. This is a fairly lenient type of comparison: an investment may be substantially suboptimal, but still be less expensive than burning oil. In this analysis, I have not attempted to identify the most economical option for reducing oil use or replacing Seabrook; my results indicate that Seabrook is so expensive that almost any alternative is likely more economical.

Q: How would the fuel cost and the total cost of Seabrook power compare to oil costs early in the plant's life?

A: Table 2.1 lists, and Figure 2.1 displays, MMWEC's projections of Seabrook 1 fuel costs, MMWEC's projections of short-term replacement power (the fuel costs of existing oil-burning plants using 1% sulfur fuel[5] and the total cost of Seabrook power under three cases: MMWEC's assumptions with a $1.3 billion cash cost to go, or about $5.5 billion total (Case 1), my optimistic case of a $6 billion construction cost (Case 2), and my less optimistic case of $8 billion construction cost (Case 3). The differential between nuclear fuel and oil fuel starts in 1988 at about 4.5 cents per kWh, and rises to 13.8 cents per kWh by 2000, while the total nuclear costs exceed the cost of oil-fired power by 16 to 29 cents in 1988, depending on the case.

Q: How have you calculated the cost of Seabrook 1 power for the cost and performance figures you derived in the DPU 84-152?

A: Appendix B derives the cost of Seabrook 1 in annual cents/kWh for the cost and performance documented in DPU 84-152. For simplicity, I have adopted the assumption about useful operating life which is implicit in the life of MMWEC's bond obligations. I have also assumed a 15% future interest rate, and the capitalizing of all interest until 1988 at 15%.

Q: Have you performed any other cost analyses?

A: I have also modelled the cost of writing off Seabrook 1 to MMWEC's ratepayers. For comparability, this Case 4 assumes

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5. MMWEC recognizes that at least some members have less expensive sources of replacement power than Stony Brook; even in the short term. In the longer term, many alternatives are available.

that the debt payments on the sunk costs are capitalized (at 15%) to 1/1/88, and are then paid off evenly over 25 years. Appendix B displays the results of this analysis in annual dollar costs. Table 2.2 presents the total and incremental cost (net of Case 4 costs) of Seabrook in cents/kWh for each of the three completion cases.

Q: How will the expensive power from Seabrook, or the cost of cancelation, affect rates for the member participants?

A: Table 2.3 presents approximate answers to this question for each of the four cases described above. For simplicity, I have not distinguished between the slightly different costs of Seabrook from the various projects, nor have I attempted to determine marginal power supplies for each member participant. Seabrook is assumed to displace other sources at 6 cents/kWh, which is comparable to MMWEC's projection. No PSNH purchase is included, due to the uncertainties in PSNH's status by 1988.

Q: Will the rate increases due to Seabrook affect the need for the plant?

A: The price elasticity impact of Seabrook 1 will certainly reduce the need for new capacity, regardless of whether the unit is completed or not. The exact magnitude of the effect will depend on such factors as the number of major customers who leave the participants' service territories,[6] the extent of rate increases before Seabrook starts to affect rates, the other cost increases which coincide with Seabrook, and the elasticities assumed. Roughly speaking, Seabrook would raise MMWEC member participants rates by 40-60% by 1988, with corresponding increases for individual members ranging from 16% for Holyoke to about 167% for Hudson.[7] The subsequent years would tend to experience smaller real increases, although the loss of sales due to the initial Seabrook rate increases will require some additional base rate increases to maintain utility revenues and meet debt obligations. The long-run demand effects of the first year price rise would be a 15-38% reduction in participant sales, ranging from a 7% to 14% decrease for Holyoke, to a 39% to 63% reduction in Hudson's sales.[8] These effects are illustrated in Table 2.4.

Q: What can be concluded from your analyses?

A: There are four major conclusions. First, Seabrook will result in rate increases of 13% - 214% for MMWEC member

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6. For some MMWEC members which serve contiguous communities, there is the possibility that large portions of their service territories will leave the member's system to become free-standing utilities or parts of IOU service territories.

7. The point estimates assume the Case 2 cost increases (see Table 2.3).

8. These long-run effects would be expected over a 15-20 year period, as compared to sales without the Seabrook rate shock. The elasticities assumed ranged from the very low (-0.5) to moderate (-1.0): the true values are likely to be larger.

participants if it's completed, with an average (revenue-weighted) increase of 39% - 61%,[9] while cancelation would result in increases of 10% - 103%, with an average of 29%. Second, as shown in Table 2.2, the levelized cost of completing Seabrook, net of the cost of cancelation, is 9.9 - 18.6 cents/kWh over the first 15 years. Third, if MMWEC or the participants have a choice between completing and owning Seabrook, or of having no liability for Seabrook, the relevant levelized cost is the total cost of Seabrook power, or 21 - 32 cents/kWh over 15 years.[10] Fourth, the rate increases resulting from Seabrook will significantly reduce MMWEC member sales.

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9. The low end of these ranges MMWEC's assumed operating characteristics and the Newbrook cost estimate, both of which are very optimistic.

10. The same is true for communities and customers served by the participants.

3 - COMPARING SEABROOK TO ALTERNATIVE POWER SOURCES

Q: How do your estimates of Seabrook 1 incremental costs compare to the rates currently offered for co-generators and small power producers in Massachusetts?

A: As shown in Table 2.2, completing and running Seabrook 1 is likely to cost 10 - 19 cents/kWh in nominal terms levelized over the first 15 years of its life, which is comparable to the horizon of a typical small-power contract.[11]

Since mainland Massachusetts utilities, including MMWEC, generally have not been willing to offer purchase contracts for more than six cents/kWh in nominal terms, much higher rates can be offered, and much more power purchased, at rates which would still represent a bargain, compared to Seabrook 1 power costs.

Q: Are 15 cents/kWh in a small power producer contract and 15 cents per kWh in expected Seabrook costs equivalent from the utility's or ratepayers' viewpoint?

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11. Note that these incremental costs are less than the total costs discussed in the previous section.

A: No. The small power producer gets paid only if it produces power. The utility and its customers must cover the cost of Seabrook whether or not it operates. Therefore, the financial and economic risks (which are not necessarily the same as the power supply risks I discuss below) of Seabrook are greater than those of a small power producer at the same expected costs, and under those circumstances, the small producer power would be preferable.

Q: Is it likely that renewing fifteen-year contracts written in this decade will require that the prices offered be increased by fifteen years of inflation?

A: I think not. Once cogenerators, refuse-burning plants, hydro-electric facilities, and the like have been built and operated for fifteen years, the cost of keeping them in operation should be very low. Depending on the regulatory environment (such as whether the small producers have the right to wheel power to other customers at regulated rates), the cost of fuel (for the cogenerators, in particular), and the economic viability of the user of cogenerated heat, the contracts may be renewed at the original rate, or even less.

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; central generators can. Most conservation procedures become effective soon after funds are expended on them; a new nuclear unit would be under construction for well over a decade before it starts to reduce oil use.

Q: Can you compare the relative risk of reliance on conservation programs, cogeneration, and small power producers, to the risk of completing and operating Seabrook?

A: Yes, at least in general terms. The types of risks involved are quite different, and quantification is often difficult. In most respects, however, Seabrook is a much riskier power source.

Consider, for example, the availability of power in 15 years. As I noted above, once a small power producer is built, it is likely to be available for a long time. Hydro plants are certainly not going to be relocated, and may well last a century. Most cogenerating industrial and commercial firms (or their facilities, which are often more durable than the corporate entities) will also stay in the area, for access to materials, labor, or customers; if the firms fail, both their supply contribution and their demand contribution (including their effect on residential sales and electricity sales to the firms' suppliers and other related commercial and industrial activities) are lost simultaneously, so the net effect is smaller than a corresponding loss of central station capacity. Similarly, many conservation investments (such as insulation, or appliance efficiency improvements) are likely to last as long as the end use with which they are associated.

More importantly, the small power producers, cogenerators, and conservation investments diversify the risk of outages or premature retirements much better than does Seabrook. The loss of any one small power producer causes a much smaller problem for New England, Massachusetts, MMWEC, or any particular utility than would the loss of Seabrook 1, either short-run (for a few hours, days, or weeks) or long-run (for months, years, or permanently). For example, the New England capacity situation was apparently somewhat tighter than usual this summer, largely because of simultaneous outages at a few nuclear plants; hundreds of small power producers would have to become unavailable simultaneously to have a similar effect.

Q: Is it possible for several small producers to become unavailable simultaneously due to a common cause?

A: Certainly. A severe drought would drastically curtail hydro generation, and introduction of a more desirable (but less energy efficient) generation of a major appliance (say, refrigerators) could undo a significant portion of an earlier conservation program. But most of these events, while they might be simultaneous, would not be fast, and would allow the utilities months or years to secure alternative sources, or to implement a new round of conservation investments.

Nuclear units can also be taken out of service by a common cause, as evidenced by the effects of the Three Mile Island accident, or the Stone & Webster computational error which shut down Maine Yankee in 1978. From the viewpoint of reliability, or energy adequacy, the loss of all small hydro, or all wood-fired cogeneration, would be much less serious than loss of all New England nuclear units. If MMWEC, or any of its members becomes highly dependent on a single type of small power producer, subject to common cause outages, it would be well advised to arrange power swaps with other utilities' power purchases (or central stations) to diversify the risk. This sort of technological risk-sharing is not possible to any great extent with New England nuclear plants, since they represent such a large share of total NEPOOL capacity and energy. Indeed, MMWEC's excessive reliance on nuclear capacity, particularly from Seabrook, has already created serious problem, regardless of whether Seabrook 1 is finished.

Q: Are there any special risks associated with nuclear plants, other than the common-cause outages, and the size of Seabrook, which you have already discussed?

A: Yes, of at least two kinds. First, there are the unique construction and completion problems related to nuclear safety concerns. Plants which appear to be progressing smoothly can be held up for months or years by last-minute problems, as with Palo Verde 1, Grand Gulf, Diablo Canyon (the 1981 OL suspension), and Byron. Plants close to physical completion (Zimmer, Midland) have even been canceled due to the cost of correcting safety problems. Many of these problems were not anticipated two years before they occurred, and there is no way of telling what, if any, suprises will turn up at Seabrook in 1986. One example of a problem which could delay or prevent the operation of Seabrook 1 would be the adequacy of emergency planning. PSNH (1984) indicates that at least some of the seven Massachusetts municipalities for which emergency plans must be developed under current NRC regulations are opposing the development of the plans, and/or the adequacy of proposals to date. Since the NRC requires certification of the plans by the Governor of the affected state, and since Governor Dukakis has indicated that he will not certify the Massachusetts plan over the objection of any Massachusetts municipality,[12] a single town could conceivably prevent Seabrook from receiving an operating license. Of course, the NRC may change its rules, or Governor Dukakis eventually be succeeded by someone with a different position, or he may change his mind, or all the communities may be satisfied by some future plan. None of these eventualities appear to be occurring in time to allow licensing of Shoreham, which faces similar local opposition.[13]

The second special uncertainty with nuclear plants is the lack of significant experience with older plants, in terms of operating costs, reliability, and particularly useful life. No plant of more than 300 MW has even reached its seventeenth birthday, and the experience of the smaller units is not encouraging, as discussed in my DPU 84-152 testimony in connection with the useful life of the plants.

Q: If the utilities continue to invest in Seabrook, and the situation there turns out badly, are the ratepayers exposed

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12. PSNH (1984), page 10.

13. There are differences between the Shoreham and Seabrook situations, since Shoreham's opposition comes from the county in which the plant is located, and Shoreham also has emergency generator problems. It is not clear how much opposition Seabrook faces from NH communities, or what the state's response will be.

to more or less risk than if the utilities invest in alternative energy and conservation programs, and those are less successful than currently expected?

A: Seabrook can fail in ways which are hardly credible for alternative energy and conservation programs. For example, the utilities could invest another billion dollars in Seabrook, without ever having it operate. It is hard to imagine how a similar investment in a diversified mix of alternative energy producers and conservation programs could fail to provide substantial benefits. Any one program may prove to be ineffective, but poor programs can be abandoned rapidly and with small losses, in favor of programs which prove to work well. The downside risk from the alternatives/conservation approach is primarily the possibility that somewhat higher prices must be paid than currently appears likely. The experience in Maine and California, among other states, demonstrates that nontraditional power supplies are available at reasonable prices, even if the price is higher than the utility would like.

Q: Does a small power producer or other power source have to provide firm power in order to be considered as an alternative to Seabrook?

A: No, not really. It is important to remember that most of Seabrook's benefits will be associated with the reduction in the use of oil, rather than the replacement of other capacity which could provide reliable power. Oil is relatively expensive: capacity, particularly in the form of combustion turbines, is not very expensive. It is also important to recall that Seabrook will not be very reliable, and due to its large size, its contribution to overall NEPOOL reliability will be quite small. Table 3.1 shows the derivation of the effective load carrying capacity (ELCC) for Seabrook, from the reserve margins projected by MMWEC. As shown in Table 3.1, MMWEC does not expect Seabrook to be able to support firm load amounting to much more than half of its rated capacity. Overall, NEPOOL's current capacity is expected to support firm peak load averaging 80% to 85% of its rated capacity. If all NEPOOL capacity had ELCC's as poor as Seabrook's, NEPOOL would need a reserve margin of around 100%.

Since Seabrook will provide little reliability benefit, and since that reliability could be provided at low cost in any case, the important comparison between alternatives is on a cents-per-kWh basis.

Q: Do NEPOOL capability rules assign capacity credits in a fair and appropriate manner across technologies?

A: No. NEPOOL capability assignments completely ignore such important determinants of ELCC as forced outage rate, maintenance requirements, and unit size. A large unreliable unit is treated in the same manner as a small reliable unit: a MW of either contributes equally to meeting a member's capability responsibility. In terms of their value for NEPOOL reliability, many cogenerators will be roughly twice as useful per kW as will Seabrook, but the utilities which pay to supply that valuable small producer capacity will not be proportionately rewarded in their capability calculations. In addition, hydro facilities are credited only for their capability in median water years, i.e., at the average of historical performance. If the same type of rule were applied to some of the large thermal units, their capacity credit would be significantly reduced.

While most features of the NEPOOL capability rules tend to understate the reliability benefits of alternative energy sources (especially small and reliable ones, such as cogenerators and wood-burning plants), some of the peculiarities of those rules will tend to overstate the value of some technologies. In particular, no plant is required to demonstrate more than six hours of continuous operation at its claimed rating, and that demonstration may be from historical records, rather than from a scheduled test. Therefore, wind plants should be able to receive credit for close to their entire capacity, even though they are generally acknowledged to have ELCC's of only about 20-30% of their rated capacities.

Q: Other than the value of the capacity to NEPOOL and the crediting of that capacity to individual NEPOOL members, are there other reliability issues which differentiate between Seabrook and small power producers?

A: Yes. Small producers which are located close to or in the service territory of the MMWEC members will also help to protect those members against transmission failures, which have historically been responsible for more customer disconnections than has inadequacy of installed generation capacity.

Q: Should the ability of the utility or NEPOOL to dispatch an alternative power source be a consideration in determining the value of the source?

A: Not in general. So long as the source would be dispatched under economic dispatch, the issue of whether NEPOOL can choose to dispatch is largely irrelevant. Thus, for plants with zero or negative fuel costs (e.g., hydro, wind, and solid waste plants), which would always be dispatched, the lack of "dispatchability" should not be an issue of any interest. As long as oil remains the marginal fuel on the NEPOOL system, virtually all alternatives will be base loaded. Only when oil is no longer the marginal NEPOOL fuel will the ability to turn off small producers with fuel costs higher than coal (or whatever becomes the marginal fuel source) be of any real importance. NEPOOL appartently recognizes that control over dispatch is not critical to capability determinations, since it gives utilities credit for their own must-run units, which for whatever reason (e.g., cogeneration demands, area protection, lack of cycling capability) are not subject to NEPOOL control.[14]

For units which are not base-loaded, the value of the capacity in emergencies will depend on the probability that the plant will be operating at the time of the emergency, NEPOOL's ability to bring the plant into operation if it is not operating, the plant's response time, and the plant's location with respect to the transmission grid, since many emergency conditions result from local transmission or

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14. MMWEC's work papers indicate some uncertainties as to NEPOOL capacity credits for cogenerators and small power producers. It is not clear why either NEPOOL or MMWEC would expect the capacity credit rules to be different for cogenerators than for utility plants. NEPOOL has rules for the testing of plant capability (NEPOOL 1977a, 1977b), including purchased power, and none of those rules allow for discrimination against units not owned by a utility. Such discrimination would seem to be difficult to reconcile with PURPA. If NEPOOL has not clearly established that small power producers will be treated fairly, MMWEC would be well advised to press this issue, either in arbitration or before the FERC (which is both the regulator of NEPOOL and the enforcement agency for PURPA), so that development is not unnecessarily delayed. Since both their technical characteristics and their legal status favor small producers, NEPOOL would be hard pressed to deny them full credits, especially since NEPOOL previously has counted the full capacity of cogenerators and small hydro stations, both utility-owned and as purchased power.

generation problems, rather than regional capacity shortfalls. These considerations are more relevant for operating reserve credits than for capability credits.

4 - ALTERNATIVE ENERGY OPTIONS

4.1 - Introduction

Q: What energy sources will you be considering in this section?

A: In general, I will discuss the availability and cost of electric power from generation techniques other than central station thermal plants. Thus, production of power from oil-fired existing stations, conversion of existing oil plants to coal or alternate fuels, construction of new fossil plants, and construction of nuclear plants other than Seabrook (e.g., Pt. Lepreau 2), will not be considered. The production of energy in forms other than electricity (e.g., from wood stoves, solar space and water heating) will be included in the next section as conservation options. The specific generation techniques I will consider include:

- wind energy conversion
- small New England hydroelectric sites
- wood fired generation
- energy recovery from solid waste
- cogeneration

- purchases from Hydro Quebec

Q: What mechanisms are available to MMWEC and its members for the development of alternative energy sources?

A: There are two basic approaches, each of which has several variants and combinations. The first approach is the purchase option: MMWEC (or the individual towns) can offer to buy power at rates which are less than the cost of traditional supply sources (existing oil and new nuclear and coal plants), but still high enough to attract and encourage development of alternative sources. The second approach is for MMWEC (or its members) to build and operate the facilities themselves.

Q: How can the purchase option be structured, and which approach is preferable?

A: The two basic approaches involve (1) setting variable rates, based on short-run costs, and (2) setting fixed rates which reflect the expected levelized cost over a lengthy period (typically 15 to 30 years). The general policy of Massachusetts utilities[15] has been to offer very low rates,

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15. Neither MMWEC nor its members appear to offer any standard rates at all. Mr. Cotte's testimony and MMWEC's workpapers indicate that MMWEC is reluctant to pay more than short-run avoided cost. This attitude has apparently discouraged some developers who have approached MMWEC, including First Equity Associates, who solicited MMWEC's interest in up to 50 MW of cogeneration in Massachusetts.

which include only short-run fuel costs. While the expected present value of these rates over the long term is substantial, they are subject to great uncertainty, and the response from potential developers in Massachusetts has not been overwhelming. As I will discuss below, much better results have been obtained by utilities which have offered levelized contracts.

Q: Why would you expect levelized contracts to produce better results than short-run rates?

A: A fixed price per kWh delivered is advantageous to the developer for two reasons: it front-loads the recovery of the initial investment (since rates in the first few years are higher under levelized contracts than under rates set on the basis of short-run fuel costs) and it transfers some of the risk from the developer to the utility.[16] Rates based on short-run costs force the developer to assume the risks associated with predictions of future oil prices, with the utility's load growth (which partially determines its marginal costs), and with the rest of the utility's power supply development. The developer retains several kinds of risk in any case, including the risks associated with cost overruns in construction, with operating costs for the

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16. If the developer is not constrained by cash flow considerations in the early years, a "ramp" rate, which increases by a predetermined schedule, or as a function of inflation, may be equally acceptable.

facility, and with energy production at the facility. Both the front-loading of revenues and the reduction in risk under a levelized rate make financing much more available to the developer, since the cash flow is advanced in time and more certain than in the short-run cost case.[17]

Q: Do these advantages for the developer equate to disadvantages for the utility and its customers?

A: No. The front-loading of recovery simply makes the small power producer more like utility-owned investments, which usually require more-or-less constant capital cost recovery over the life (or the early years thereof) of the plant. The transfer of risk is actually advantageous to the utility. Under the short-run rates, the purchase rate is highest when the utility's other power sources are most expensive, and the alternative energy source does nothing to stabilize power costs. Under the levelized rates, the facility is most valuable to the utility when it needs the power most -- when other power sources are most expensive -- and least valuable when the rest of the utility's power supply is most favorable. Thus, the levelized rate is a form of insurance for the utility, and is actually more valuable to the utility than short-run rates with the same expected value.

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17. Com/Electric has agreed in at least one case to a short-run avoided-cost rate with a floor, which alleviates some of the financial problems and risks for the developer.

Levelization locks in the rates of prices competitive with projected power costs, and protects the utility from future oil price shocks.

Q: Why might MMWEC or its members prefer to build and operate their own alternative energy facilities, rather than purchase the power from an independent developer?

A: Depending on the specific situation, MMWEC or its members may be able to finance the project at a lower cost than an independent developer, due to the availability of tax-exempt financing. MMWEC's present financial position (a result of the risks attending its nuclear investments) reduces the differential between municipal and commercial financing rates, but project-specific financing for non-nuclear projects may still be available at rates close to those of investment-grade tax-exempt bonds. The individual towns[18] would often have access to lower cost financing than MMWEC does, although they would be limited to ownership of facilities within their service territories, unless they wish to seek special legislation.[19] Private developers may also be able to utilize tax credits and depreciation, which tends

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18. For some MMWEC members, this would include contiguous towns served by the member light department.

19. If the members were generally interested in financing power production facilities outside their service territories, they could file legislation to allow all municipal light departments to develop certain types of facilities, regardless of location.

to lower the cost of capital. Some independent developers might be other municipal governments, state agencies, or non-profit institutions, each of which faces its own set of financing problems and advantages. In the subsequent cost analyses, I will use a tax-exempt financing cost of 12%, which could be either an MMWEC project-specific rate or a member's financing cost. Unless the member's financing is very small, or the member's credit rating is very low, it should be able to finance at a cost less than 12%.

More generally, MMWEC or its members may find it less expensive to develop some energy sources directly, rather than through separate owners. This can result from the administrative and organizational economies of an integrated organization, or simply from the utility's ability to capture all the benefits of facilities it owns, rather than sharing those benefits with an independent developer.

Q: Is there any reason for purchase to be preferable to direct ownership?

A: Yes. I have already mentioned the possibility of an independent developer having lower net financing costs than MMWEC, and the minor obstacle facing light department ownership of facilities outside their service territories. Perhaps the greatest advantage of independent ownership is that it allows developers to invest in facilities and processes in which they have greater faith than that of the utilities. The developer of a cogeneration facility need not convince MMWEC that the user of the heat will be in business for 20 years in order to negotiate a reasonable contract: if the user goes out of business or moves, it is the developer (who may well be the heat user) who loses the initial investment, or earns no return on it for the period the facility lies idle.[20] Similarly, the developer need not demonstrate the reliability of his plant in order to get a contract: if the plant does not run well, he will not earn much, but that should have little effect on the rate MMWEC is willing to pay per kWh.

Q: What kinds of combinations of these approaches are possible?

A: The arrangement may start out as a straight-forward purchase, with the utility gradually buying out the developer. The developer may build and operate a facility until it meets certain standards, and then turn it over to the utility for a previously set price. The developer and the utility may jointly own the facility: in the case of cogeneration and soild-waste-fueled plants, in particular, the developer may own the boiler and associated auxiliaries, and sell steam to

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20. The utility purchaser may have paid more for the power delivered than that power was worth, but at least the payments stop when the plant stops working. If the utility owns the plant (whether it is alternative or conventional in nature), its costs continue if the plant ceases to operate for a long period, or even permanently.

the utility for its turbine (some of which may then be resold after it passes through the turbine). Alternatively, the utility may own a cogeneration facility (even if it is located on the premises of the steam user) and sell both steam and electricity.

Q: If MMWEC chooses to offer long-term contracts for the purchase of power from small producers, what level of response might it expect?

A: It is difficult to answer that question with great specificity, since it depends on the resources, ingenuity, and finances of numerous developers, manufacturers, building owners, land owners, and others, as well as the technical problems and opportunities offered by each site. However, a similar experiment was recently conducted in Maine. The Maine utilities had previously offerred small power purchase rates based on short-term fuel costs, similar to the rates currently offerred in Massachusetts. Earlier this year, the Maine PUC ordered those rates replaced with levelized contracts, with 15-year contracts paying 9.4 cents/kWh. Even though those rates have since been reduced, as cogenerators and small producers (hydro, trash-burning, and wood-burning) have backed out the utilities' most expensive sources, at least 360 MW of small power sources are now under contract. NEPOOL currently projects only 188 MW's of small power in all of Maine by the end of the century; in less than a year, Maine has brought twice that much into the pipeline at prices much lower than the cost of Seabrook.

The corresponding NEPOOL estimate for Massachusetts independent production in 1999 is 390 MW, of which only a small portion is under contract. If the Maine experience is any guide, increasing the bid price to 9 - 10 cents (which is less than the forward cost of Seabrook power, even under an optimistic $6 billion cost estimate) would be expected to double the offered power, providing another 390 MW, in addition to the portion of the original 390 MW projection not yet under contract. These capacity figures refer to short-run effects: development by the end of the century, or even the end of the decade, would be expected to be larger. Since the investor-owned utilities in Massachusetts have shown little interest in paying rates for purchased power which are comparable to what they are willing to pay for completing and running Seabrook, most of this new Massachusetts power, and probably some from neighboring states, would be available to MMWEC.

Of course, for small power production, Maine is better situated than Massachusetts in some important ways, including the size of the forest products industry, a good site for cogeneration. On the other hand, Massachusetts has more large commercial and institutional buildings, which may also offer good cogeneration sites, and the estimated response in Maine includes only the projects which materialized quickly in response to the higher prices: more offers would be expected as additional sources are developed.

Q: Should the Maine experience be any comfort to MMWEC, other than by suggesting that reasonable purchase prices could achieve the same effect in Massachusetts?

A: Yes. Central Maine Power (CMP) has offered to wheel or resell some of the power from its QF's to MMWEC. It does not appear from MMWEC's workpapers that it has explored the availability of power from the two other Maine utilities. CMP has offered up to 60 MW of power at 9-10 cents/kWh over a 15-20 year contract starting in 1987, or a phase-in of rates, starting at 6-7 cents.[21] These rates are lower than the cost of completing of Seabrook, and it is difficult to see why MMWEC would not contract for all the power CMP can supply, unless MMWEC believes that there are still less expensive options available.

Q: Does MMWEC consider that it has thoroughly explored the possibility of cogeneration and small power development in Massachusetts?

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21. I understand that developers of some 130 MW of Maine cogeneration which is not yet under contract are interested in selling their power directly to out-of-state utilities.

A: No. MMWEC's Senior Power Contracting Specialist described MMWEC's situation as "purchasing co-gen energy from Maine without looking in Massachusetts first" (Memo of 7/17/84, MV Magyar to Division Manager Power Management). Most of the documents which MMWEC provided in this case concerning cogeneration and small power production concern offers and solicitations of interest from potential sellers, rather than MMWEC's efforts to "look" for opportunities in Massachusetts or elsewhere, with the exception of some small hydro developments.

Q: Has MMWEC been properly comparing the costs of alternative energy sources and of conventional sources?

A: No. MMWEC has been very reluctant to enter into any ownership or purchase arrangement for small power sources which does not represent immediate savings compared to the cost of oil. This is a much stricter standard than is usually applied to conventional sources, and is inconsistent with Mr. Cotte's position that MMWEC and New England face imminent capacity shortfalls.

Q: Do you believe that there is considerable potential for development of conservation, small power production, and other alternatives to Seabrook, if that unit is not built?

A: There is much evidence to support that view. Utility resourcefulness and success in utilizing unconventional supply sources has been dependent in the past on the utilities' situation. For example, New England utilities seem to have become much more interested in (and successful at) obtaining agreements to purchase Hydro Quebec power as Pilgrim 2 construction became less likely. Perhaps the most aggressive conservation and small power production programs in the country are found in California, where licensing and construction problems with central generating stations left the utilities with little choice but to innovate.

Q: In his direct testimony in this case, Mr. Cotte appears to suggest that the cost of oil is a proxy for the cost of alternatives. Is this likely to be the case?

A: There is no reason why it should be. Certainly, MMWEC or its members can develop alternative power sources which are much less expensive than burning oil, depending on the quality of the resources available. Purchased power may also be less expensive than oil. As I have explained, developers appear to prefer fixed price contracts, and may well accept them for less than the expected price of oil, and with little of the attendent risk. Mr. Cotte provides no support for his rather suprising assertion, and he is certainly wrong. Many conservation techniques are much less expensive than oil, Seabrook, or any new central station source, as will be discussed in the next section.

Q: What information will you present in the subsequent subsections?

A: I will provide whatever information I have been able to assemble which provides a basis for comparison between Seabrook and each of the alternative energy sources I will discuss. The information will variously include maximum, minimum, and likely resource availability, and the approximate cost, for either generic or specific projects. Within the very abbreviated time frame of this proceeding, it is not possible to do justice to all, or even most, aspects of alternative energy development potential: my examination is generally limited to the review of analyses which were completed before the schedule for this case was established. The objective of this review is to estimate the amounts of power which would be available to MMWEC at costs comparable to, or lower than, the cost of completing and running Seabrook, and to determine whether rates and reliability of the MMWEC memebers are likely to suffer in the event that Seabrook is not completed.

While it is difficult to determine the cost or potential of any particular technology precisely, the following subsections are presented in approximately the order of increasing short-term potential.

Q: What Seabrook power cost will you use for these comparisons?

A: I will compare the options to a 15 cent/kWh cost, which is likely to be exceeded by Seabrook, if it is completed. Short-term purchases which are not expected to be renewed, or which may require much higher prices at renewal, would have to be priced at a somewhat lower level to be considered competitive with Seabrook. I will attempt to limit the analysis to individual projects which are less expensive than Seabrook: the average cost of replacement power sources can be less than that of Seabrook, even if some of the individual projects are more expensive than Seabrook.

4.2 - Wind

Q: Are wind powered generators likely to be economically competitive with Seabrook at favorable sites in and near Massachusetts?

A: Yes. A recent study for the EOER (Vachon, 1984) indicates that wind turbines with favorable private financing (a fixed charge rate of 17%) at good sites (with mean wind speeds exceeding 15.5 mph) can produce power at prices likely to be lower than those of Seabrook. Municipally owned wind systems financed at 12% over a life of 20 years [22] would have fixed charge rates of 13.4%, and would be competitive with Seabrook at wind speeds below 14 mph. Table 4.1 extrapolates these results from Vachon's busbar costs for higher fixed charge rates. Depending on tax advantages and other considerations, private ownership may be even more attractive. The necessary wind speeds are found in both coastal and mountain terrains in Massachusetts. The Vachon study is attached as Appendix D. The costs reported in the Vachon study are for current or near-term projects: wind turbines are still a rapidly evolving technology, and the California Energy Commission (June 1984, Appendix F) expects costs to fall for the rest of the decade. Excerpts from the California Energy Commission

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22. The California Energy Commission (June 1984) estimates 30 year lifetimes for wind turbines.

study are attached to this testimony as Appendix G.

At present there are two wind "farms" in Massachusetts. One, a privately owned facility in Nantucket which began operation in August 1982, currently has 8 machines and a total peak generating capacity of over 300 kW. A similar 8 machine project built and owned by the Princeton Municipal Light Department was completed earlier this year. There does not appear to be any comprehensive analysis available of the wind resource potential in the Commonwealth. Two wind farm developments totaling 15 MW, are in the planning stage. The developer of these projects also has options on other properties in Massachusetts with favorable wind regimes which could accomodate another 70 MW.

4.3 - Hydro

Q: Is there likely to be substantial potential for hydroelectric development within Massachusetts and New England at costs below the cost of power from Seabrook?

A: Yes. Reports by the New England River Basins Commission (NERBC 1980, 1981) identified 55 sites in Massachusetts which could produce a total of 129 MW's and 448 annual GWh for less than 12.5 cents per kWh (nominal) at an interest rate of 15%.[23] Another 1000 MW's in other states were identified as being feasible under the same criteria. More capacity would be available at higher power costs (though still less than likely Seabrook costs) and at lower municipal financing costs. A recent study by Smart (1984) for the EOER found that developers and potential developers of hydroelectric projects in Massachusetts had encountered problems in obtaining favorable terms and conditions for sales to utilities. In particular, even for the projects listed as discontinued, substantial numbers of the developers indicated that the projects could be revived and completed if level costs of 8 to 10 cents per kWh were available. At 10 cents, approximately 43 MW of new projects were considered to be

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23. A small amount of this capacity has since been developed, but some feasible sites were apparently omitted from the study (Smart, 1984, page 27).

viable (Smart (1984), page 23).[24] Rates comparable to the cost of Seabrook would further increase the amount of viable new capacity towards the potential identified by NERBC. The Smart study is attached as Appendix E to this testimony.

MMWEC's own studies (MMWEC, January 1983) indicate that some of the sites it has dismissed as "uneconomical" would produce less expensive power than would Seabrook. The 3 MW Windsor Locks Canal project was deleted because the power cost was projected to be 13.4 cents/kWh, and the 560 kW Collins project was dropped due to "marginal economics" at 9.1 cents/kWh. The 11 MW Stillwater project was cancelled due to "technical uncertainties and public opposition", despite a projected cost of only 11.3 cents/kWh for a late 1987 in-service date.

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24. This analysis assumes the distribution of sites for which survey data was not available was the same as the distribution in the survey results.

4.4 - Wood and Other Biomass

Q: What does wood-fired generation cost?

A: The California Energy Commission (June 1984, Vol I, page 6) reports a cost of 11.8 to 14.0 cents/kWh for a privately-owned wood-fired plant entering service in 1990. The fixed costs and O&M total 5.6 cents (or 3.8 cents for municipally-owned facilities), which would be about 15% lower for a plant starting up in 1988, or 3.2 - 4.8 cents/kWh. Excerpts from the California Energy Commission study are attached to this testimony as Appendix G. MMWEC projects that the levelized cost of fuel for the McNeil wood-fired plant in Burlington, Vermont for the 1988-2000 period will be 6.2 cents, indicating that the levelized cost of power from a new plant might be about 9 to 11 cents/kWh. The fuel cost could be reduced considerably by operating the plant as a co-generator.

Q: What is the potential for development of wood-fired generation in Massachusetts?

A: A recent study for the EOER (Pequod 1984) indicates the potential for 80 to 120 MW's of wood generation in western Massachusetts. That study is attached as Appendix F to this testimony.

Q: Would a long-term contract for power from the existing McNeil unit be competitive with the cost of Seabrook?

A: Yes. MMWEC's projections of total power costs from McNeil are equivalent to less than 11 cents/kWh, levelized from Seabrook's inservice date through the end of the century, as demonstrated in Table 4.2.

Q: Are there other forms of biomass energy production which may be feasible for MMWEC to develop?

A: Yes. These include generation (or cogeneration) of electricity from agricultural waste products, either through direct combustion, gasification, or anaerobic digestion (to form methane for combustion); similar treatments for sewage sludge; and the recovery of methane from older landfill sites. I have not attempted to calculate costs or potential for these sources. However, methane recovery from landfills appears to have comparatively low costs of production (Pequod, 1984). A facility in Brattleboro, Vermont is already generating electricity, and several developments in Massachusetts are under consideration, including Worcester and Randolph. Unfortunately, because of variation within and between sites, it is not possible to estimate the statewide potential in this resource area.

4.5 - Solid waste

Q: Are power plants which burn solid waste economically feasible?

A: Yes. The exact busbar cost depends, among other things, on the tipping fee which can be charged for the waste disposal service, but it is clear that many plants can provide less expensive power than Seabrook. MMWEC's Exhibit RMC-34 lists four facilities in New England which have contracted to sell power at prices 10% to 20% below incremental fuel costs of NEPCo or Commonwealth Electric. These utilities (particularly NEPCo) are likely to have lower incremental costs than MMWEC's participants, so MMWEC could probably negotiate contracts which include even greater discounts from incremental cost.[25] Another contract listed in the same Exhibit provides for 9 cents/kWh in 1987, escalating at half the GNP deflator; at 6% inflation, this agreement would result in levelized costs of about 10.5 cents through 2000. The final contract provides for a fixed rate of 11.99 cents/kWh for 12 years, which would still be less expensive than Seabrook.

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25. The relationship between incremental fuel cost and Seabrook costs is quite uncertain, but Exhibit RMC-34 demonstrates that Mr. Cotte's contention that oil is a proxy for alternative energy development is incorrect.

Q: How much additional waste-burning capacity can be developed in Massachusetts?

A: A recent analysis of this issue for the EOER (Pequod 1984) indicates that the total potential is 400 MW, of which about half may be available for energy recovery projects. There are currently 50 MW's of such capacity in service in the state, with 35 MW more under construction in North Andover (the NESWC project) and another 40 MW planned in Rochester (the SEMASS project), both of which are under contract to utilities. A small facility in Pittsfield uses about 7 MW of waste, but produces only steam: conversion to cogeneration may be feasible. Thus, at least 75 MW of additional capacity appears to be available, through expansion of existing sites or development for new projects, several of which (totaling up to 150 MW) are under consideration.

4.6 - Cogeneration

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

A: It would appear so. The Governor's Commission on Cogeneration (1978) developed 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 **Power Engineering** (1978). 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 cent/kWh O&M, and a heat rate of 4417 BTU/kWh. For steam turbines in general, **Power Engineering** estimates 5000/kWh and $500-$600/kW. The 230 kVa cogenerator installed at Middlebury College in Vermont in 1980 cost $50,000 (or about $250/kW), in addition to some installation costs which are not separable from other efficiency improvements.

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 kWhs for each kWh produced at conventional heat rates. Therefore, an 80% cogeneration capacity factor can be interpreted as a 32% to 40% capacity factor at conventional heat rates and 40-48% capacity factor at a free heat rate. In order to calculate a cost of cogeneration which is independent of the price of oil, it is useful to examine only the capacity factor from the "free" generation, net of equivalent conventional oil generation.

Table 4.3 presents the cost of cogenerated electricity from steam-turbine cogeneration plants under various assumptions regarding capital cost and heat rate. The O&M cost used in that Table is twice the level of the Governor's Commission report, to allow for inflation. The highest capital costs generally refer to smaller steam turbine plants. As the Middlebury experience indicates, small cogenerators on existing steam systems can be very inexpensive. The kWh's generated at the conventional heat rate are assumed to cost about as much as conventional running costs. This assumption may be pessimistic, since 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.[27]

The net power costs in Table 4.3 range from 1 to 7 cents/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 0.4 cents/kWh to the year 2000.

Even under the worst-case assumptions, these installations would provide electricity for much lower cost than would Seabrook. In addition, their small size, high reliability, and dispersed siting would give the cogenerators a much greater contribution to reliability than a similar amount of nuclear capacity (per kW or per kWh); 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

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27. On the other hand, some small systems may burn #2 oil, although natural gas, where available, can generally replace the #2 oil at prices similar to #6 oil, by MMWEC's own projections.

lower, depending on the additional costs of handling the fuel and its by-products.

Q: Are there any recent estimates of the potential for cogeneration development in Massachusetts and New England?

A: I know of no comprehensive study. A study for the DOE (General Energy Associates, 1983) examined just the potential in large cogenerators (of at least 500 kW) at specific industrial facilities. The DOE study found 124 potential plant sites, totaling 973 MW and 5047 GWH of annual generation, in Massachusetts alone, with 1346 MW (and 9243 GWH) more in Maine, and another 1073 MW (and 6120 GWH) in the other New England States. All of these sites were economically profitable for private investors at 7% real return, or about a 14% nominal return at MMWEC's projected inflation rate of 6.5%; this is certainly a reasonable return on municipal investments financed with tax-exempt bonds. The particular calculations used in this study were not really suited to MMWEC's particular situation, since it includes tax effects, somewhat high purchased power rates, and very high fossil fuel costs (residual oil in New England is assumed to cost $7.29/MMBTU in 1985, in 1980$, or about $10.35 in 1985$, as compared to MMWEC's projection of $4.69/MMBTU in 1985 for 1% sulfur).[28] Overall, the high fuel cost (relative to the

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28. The study also assumes entirely new systems are required, and does not give credit either for existing boiler investments nor

buyback rate) probably causes the potential to be understated for investments competitive with Seabrook.

Q: Are there likely to be other sites in Massachusetts in which cogeneration is feasible?

A: Yes. Commercial facilities (office buildings, shopping malls, commercial laundries, restaurants), institutions (mostly schools and hospitals), and multi-family residential buildings all offer the possibility of successful cogeneration development. A recent study for the EOER (ARS, 1984) indicates that a minimum of 25 to 40 megawatts of cogeneration capacity can be developed at hospitals, hotels, and office buildings. If cogeneration was pursued at all of the facilities in these categories which ARS estimated to have adequate thermal load to justify cogeneration (220 buildings), approximately 80 megawatts would be available. These figures are probably understated in several ways. ARS assumed private ownership, 20-40% required return on investment for most sectors, a high standby power charge ($100/kW-year), and constrained the minimum system size to 500 kW in hospitals and 300 kW in other buildings. At a return of 10-19%, only 10% of the market potential is assumed to be realized. The number of buildings in the hotel and

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for replacement of aging boilers. In addition, the costs assumed for steam turbine systems are much higher than those in the previously quoted sources, perhaps because of the differing assumptions about boiler value or replacement. The study also does not examine space constraints in existing facilities.

office categories are lower bound estimates, and the potential for cogeneration in schools, apartment buildings, restaurants, and laundries was not considered. Since ARS's estimate of the potential for industrial cogeneration development only range from about 15% to about 40% of that of General Energy Associates (using the same facilities data, but imposing similar limits in system size and investment return), it is likely that its assessment of commercial potential is similarly understated, even in the sectors it examined. The ARS study is attached as Appendix H.

Q: Are cogeneration systems available in smaller sizes than those considered by ARS?

A: Yes. Commercial systems are available at least down to 60 kW size.

4.7 - Hydro Quebec

Q: Is additional power likely to be available from Hydro Quebec?

A: Yes. Hydro Quebec is presently embarked on an aggressive marketing program to utilize its excess capacity. This program includes incentives for the conversion of industrial boilers to electricity, which is an extremely inefficient use of electricity. In addition to the current surplus, Hydro Quebec officials have informed the EOER that an additional 15,000 MW of capacity could be developed in the 1990's (in addition to the 2600 MW La Grande 4 project due to enter service in 1985), if there were a long-term market for the power, and that Hydro Quebec would be willing to enter into long term contracts for such power. While MMWEC's access to this power would depend on cooperative action by several New England utilities, particularly in the development of the necessary transmission facilities, there appears to be substantial potential for purchases from Quebec, if New England actually faces a tight capacity situation in the next decade.

4.8 - Alternatives Summary

Q: How much potential exists for development of alternative energy sources in Massachusetts and New England?

A: Table 4.4 lists the amounts of potential capacity, typical actual or estimated capacity factors, and the range of costs for each source. Even where the cost range is not well defined, the potential is estimated for individual projects with levelized costs below the cost of power from Seabrook, and in some cases much below. Sources for which the potential is likely to be significantly underestimated are indicated with a plus (+). This Table does not include the thousands of megawatts which should be available from Hydro Quebec.

Q: How do these amounts of capacity compare to MMWEC's projected capacity shortfall in 1999/2000 without Seabrook?

A: MMWEC projects a shortfall of 492 MW in 1999/2000 under its base case load forecast. This appears to be a small portion of the available cogeneration and small power production capacity, especially if Hydro Quebec is included in the potential.[29] Since NEPCo does not anticipate the need for

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29. MMWEC's capacity requirements may also be reduced if it is able to take advantage of the internal diversity of its members, as do the utility holding companies, the Vermont group, and the Connecticut municipals. MMWEC is unique in New England, in that

further construction in this century, even without Seabrook and with rather small contributions from alternative energy sources (200 MW for the entire NEES system), and since the investor-owned utilities have not been agresssive in pursuing alternative, a relatively large share of Massachusetts and New England capacity should be available to MMWEC.

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its members are responsible for reserves above their individual peak loads, rather than for a share of the lower system diversified load.

5 - CONSERVATION

5.1 - Conservation Objectives and Program Design

Q: What forms might a MMWEC conservation program take?

A: There are many possible models, which can generally be pursued simultaneously. The various approaches can be separated into five major groupings: direct implementation, directed incentives, open purchase programs, rate design, and requirement programs.

Q: Is an MMWEC conservation program of some form essential at this point?

A: Yes. Significant energy conservation on the MMWEC system is virtually certain over the next several years, as a result of costs of either completing or canceling Seabrook.[30] These cost-induced conservation effects are discussed in Section 2. The choice facing MMWEC and its members is not so much whether there will be conservation, as whether that conservation should occur through an orderly program of

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30. This conclusion assumes that MMWEC will not be able to recover significant damages from other parties, that MMWEC's members will continue to exist, and that they will have to pay for their share of the project under the Power Sales Agreements. None of these conditions are inevitable.

efficiency improvements, or whether that conservation will occur through painful reductions in living standards and economic activity, as a response to higher rates.

Q: What are direct implementation programs?

A: Direct implementation programs are characterized by the utility providing a service or contracting for performance of the service. An example of a direct implementation program would be the Northeast Utilities Wrap-Up/Turn-Down Program, under which utility employees or contractors go to customers' premises and adjust water heater aquastats and install insulation blankets, for a nominal fee ($5). For larger projects, such as ceiling insulation or heat pump installation, the direct implementation may be combined with a loan program, to match the savings to the payment period.

Q: What do you mean by directed incentives?

A: Directed incentives programs include grants, loans, and rebates. Rather than actually performing the conservation, the utility achieves the same end by rewarding customers who make conservation investments.[31] Federal and state conservation and alternative energy tax credits are directed

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31. Since the utility may also arrange for the work to be performed, some incentives programs shade into the direct implementation programs.

incentives,[32] as are many existing utility conservation programs. Low interest loans are used by many utilities,[33] while many others provide rebates for the purchase of appliances of more-than-average efficiency.[34] In the case of loans, the utility can combine a direct discount (to reflect the benefit of the measure to the utility), access to the utility's lower cost of capital (particularly relevant for municipal utilities), the convenience of a single bill for electric service and loan payment (which may also ensure collection), and the assurance that the total bill for conservation and electricity will be lower than the electric bill would have been without the conservation. The last result can be achieved by charging the customer for a fixed number of extra kWh (e.g., 50% of the estimated savings from the conservation investment), in addition to the metered use. If the utility's costs rise rapidly, so do the customer's savings, and the loan is paid off quickly: if

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32. Unfortunately, these are not very well directed programs, since they reward consumers for spending money, rather than conserving energy: they would be much more appropriate if they were tied to the amount of conservation or energy production, rather than to the amount of money spent.

33. Again, the size of the incentive should be tied to the value of the measure, rather than the cost of the measure. A customer who insulates his own ceiling should not receive a smaller incentive than one who hires professionals to do the same job.

34. Care must be taken in such a program to ensure that it is structured to encourage appliance efficiency, rather than appliance purchase. Requiring the trade-in of an old appliance, or limiting the rebate to such universal appliances as refrigerators, may help to target the incentives.

rates rise slowly, the loan is paid back more slowly.

Q: What would an open purchase program entail?

A: An open purchase program for conservation is the demand-side equivalent of PURPA rates for small power producers. In one way or another, a price is offered for conservation, and suppliers (customers, contractors, and other entities) are paid for the amount of conservation they provide. The utility can either set a price for conservation (as it does for power purchases) and buy all the conservation offered at that price, or require suppliers to bid for the right to provide conservation services, with the lowest bidders being accepted. Appendix C to this testimony is a copy of my paper on open purchase conservation program design. The paper was presented to the International Association of Energy Economists' convention in November, and will be published in the conference proceedings.

Q: What is the relationship between rate design and conservation?

A: It is clear that electricity consumers respond to the rates that they pay. Conservation can be encouraged by collecting revenues through charges in the tail energy blocks, rather than through customer charges, demand charges, or inner blocks of energy consumption; by increasing rates to reflect marginal cost; and by posting higher prices for the most price-elastic end uses. Excess consumption can be encouraged by reversing these measures: unfortunately, many MMWEC members still have rate design features which were more appropriate in the 1960's than in the 1980's.

Q: What do you mean by requirement programs?

A: Requirement programs would include measures which withhold service, or charge higher rates, or otherwise discourage or prevent the installation or continuation of inefficient uses of electricity. Examples would include surcharges for energy-inefficient buildings and equipment, building code requirements of higher building shell and equipment efficiency, appliance efficiency requirements for new sales, and hookup charges for new construction based on expected electricity use. Some of these measures require governmental action: due to their small service territories and their close relationships with municipal governments, MMWEC's members seem especially well positioned to take advantage of building codes and appliance efficiency requirements. Other measures can be integrated into rate design and other conservation programs: surcharges for energy inefficiency can help pay for grants for conservation investments, for example.

Q: Are you suggesting that MMWEC members can refuse to serve customers who do not meet prescribed efficiency standards?

A: It is possible that the members could do so, but that is a legal issue, and I am not addressing it. If MMWEC members can not refuse service to non-complying customers, they can achieve much the same effect by prevailing upon their towns to implement higher building code standards, at least for electrical use efficiencies. Alternatively, the members can impose rate penalties for non-complying customers, or rate incentives for complying customers, so as to make inefficient energy use unpalatable, even if it is still possible.

Q: Are there reasons to believe that there are significant opportunities for conservation investments at costs competitive with new central station construction?

A: Yes. It is widely recognized that there are large energy conservation investments which are economical at current energy prices, but which have not been pursued by consumers due to lack of information, capital, or inclination. A consultant to Central Maine Power noted that:

> While [increased insulation and appliance efficiency] are clearly economic at current prices, numerous studies have shown that many household do <u>not</u> make conservation investments which are economic. CMP's experience is consistent with this finding. (NERA, 1984, p. IV-5)

In addition, changing conservation technology continues to create new opportunities for investment in energy efficiency. Thus, there is a stock of untapped potential conservation investments in existing end uses which is economical at current prices, and an even larger stock which is economical at prices competitive with Seabrook. In the commercial and industrial sectors, it is reasonable to expect for similar reasons that there are probably similar opportunities in conservation, some of which can be tapped by proper price signals, and some of which may require direct utility involvement in design, financing, and risk-sharing.

Q: Are conservation programs of various types being pursued by other utilities?

A: Yes. Unfortunately, many utility conservation programs are very limited, and others contain significant promotional features. However, some effective and relatively comprehensive conservation programs have been instituted by utilities. Appendix J excerpts portions of an EPRI study (Blevins 1984) which lists 351 projects by 141 utilities, some of which appear to be quite serious. These projects reported 3,516,507 installations in 1983.

The Pacific Northwest Power Act, passed in 1980, gave explicit precedence to conservation and alternative sources over new nuclear and coal units. The emphasis on conservation is clearly demonstrated in the EPRI study (Appendix J). In 1983, utility conservation programs reported 1.5 million installations in the Northwest region, over 40%

of all reported installations nationwide.[35] Conservation programs in this region utilize many of the approaches which have been described previously in this section. The programs also include many of the specific conservation techniques which I address later in this section: building shell and water heater insulation, replacement of existing electric and water space heating equipment with higher efficiency equipment such as heat pumps, and lighting efficiency improvements. The results reported in the EPRI study (Appendix J, Tables 3-12, 13, 14, 26, 27, 28) indicate substantial energy savings.

California utilities have instituted large and effective conservation programs in response to licensing and construction problems with central generating stations and strong encouragement by regulators. Appendix I contains descriptions of some of these programs. If Mr. Cotte's testimony has correctly projected New England load and supply (either with Seabrook, or without), MMWEC will soon be in a situation comparable to that of the California utilities.

General Public Utilities, faced with high energy costs and an

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35. The EPRI study's definition of the Northwest region appears to include some areas, such as Utah, which are outside the region affected by the Pacific Northwest Power Act.

inability to finance new capacity in the wake of Three Mile Island, has established a substantial conservation program. The EPRI study (Appendix J, page 3-57) describes the utility's program to weatherize 150,000 electrically heated homes. Contractors are paid to perform the retrofit with the payment proportional to electricity savings. Program costs of 3 cents/kWh and savings of 18% per home are reported.

The Tennessee Valley Authority has sharply curtailed its once massive nuclear construction program and has initiated some very extensive conservation efforts. The EPRI study (page 3-65) reports on a TVA program to weatherize 690,000 living units with projected annual savings of 2.5 million kWh and 1200 MW. This program, which provides zero and low interest loans and free energy surveys, has been ongoing since 1977. Another TVA program (reported on page 3-137) provides similar incentives for commercial and industrial conservation measures with savings estimated at 275 MW and 673 million kWh. TVA also provides similar incentives to encourage residential retrofits of air and water source heat pumps and heat pump water heaters (see page 3-137).

Several Texas utilities have instituted incentives for installation of efficient appliances (air conditioners, heat pumps, heat recovery water heaters). Texas Electric Service reports (page 3-137) load reductions for the residential and commercial/industrial sectors at average costs of \$195/kW and \$150/kW. This utility also reports (page 3-132) savings from a lighting efficiency program at a cost of \$58/kW.

Q: Is the experience of these other utilities in conservation programs applicable to MMWEC and its members?

A: The utilities described above are a highly diverse group including both IOU's and several types of public ownership and a wide variety of supply and customer mix, climate, and regulatory policy. The specifics of conservation programs vary widely. However, the potential amount of cost-effective conservation is, in all cases, very substantial. The utilities with effective conservation programs are those which have established conservation as an important goal and provided resources to competently achieve this goal. MMWEC and its members present a specific set of opportunities and problems. Public ownership and the close connection between the town governments and utilities frees MMWEC's members from many of the institutional constraints that face other utilities. However, MMWEC's individual members are relatively small by utility standards (some are very small), so it may be difficult for them to individually manage a comprehensive conservation program. MMWEC's members can deal with this problem by engaging in cooperative efforts and resource sharing. MMWEC itself could be an effective channel for this cooperation.

Q: Mr. Cotte's testimony suggests that a 10% reduction in energy use is the maximum achievable, based upon the experience of NEES with NEESPLAN and Boston Edison with IMPACT 2000. Is Mr. Cotte correct?

A: No. It is difficult to follow Mr. Cotte's reasoning in this section of his testimony (pages 16-17), but he appears to be suggesting that the arbitrary conservation and load management[36] figures included in these private utility business plans are firm limits on the available resource. There is no reason for this to be true, and several for it to be false. Neither NEESPLAN nor IMPACT 2000 is a maximal conservation program. Neither utility has claimed that it has defined technically or economically achievable limits to the conservation portions of their business plans: they appear to have simply backed out the amount of conservation and load management necessary to meeting their load forecast and oil-reduction goals, given their other plans.[37] Neither

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36. The emphasis on load management, rather than conservation, by these utilities is quite revealing. Load management, which does very little to reduce New England's reliance on oil, can be used as a marketing tool by offering low off-peak or "controlled" rates. Conservation, which can actually reduce oil dependency by reducing sales, is largely neglected.

37. Mr. Cotte notes that NEES has lowered its conservation and load management goals since the original NEESPLAN; he apparently misinterprets this as representing a conclusion by NEES that the original allotment of conservation and load management was unattainable. In fact, as NEES has lowered its load forecast,

utility has a particularly aggressive conservation program in effect, and Boston Edison has been repeatedly ordered by this Department to upgrade its program. IMPACT 2000 is not projected to have any conservation or load management effect until 1992, so its effectiveness can hardly be judged from load growth in 1982 and 1983, as Mr. Cotte suggests. Finally, IMPACT 2000 contains some promotional programs, intended to increase sales rather than to increase efficiency.[38]

Mr. Cotte also assumes that his low-band forecast includes all feasible conservation opportunities. I see nothing in the forecast documentation to suggest that MMWEC's forecasters even assessed conservation potential, and Mr. Stinson was not able to quantify the conservation effect assumed in the forecast.

Q: Are you aware of the level of conservation activities of the MMWEC members?

A: Yes. I have reviewed the results of a survey by the Northeast Public Power Association on this subject.

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the amount of conservation necessary to meet its goals has decreased, and NEES has decreased its targets accordingly.

38. The Carolina Power & Light conservation program description which Mr. Cotte supplied in response to IR AG 2-57 indicates a conservation and load management goal of about 25% of current peak, by 1995.

Q: Would it be appropriate to say that the MMWEC members currently have aggressive conservation programs in place?

A: No. The programs reported are far from comprehensive. Since the members are not pursuing all feasible conservation, it is hard to see why Mr. Cotte would believe that the MMWEC forecast would include all feasible conservation.

Q: What specific conservation techniques will you be addressing?

A: I will address a sampling of the available techniques, separated into the following groups:

- building shell insulation
- other space heating conservation techniques
- hot water energy conservation
- lighting efficiency improvements
- residential appliance efficiency
- rate design
- other conservation options

The time constraints of this case preclude any more than the most superficial discussion of each technique. It should be noted that all of the heat loss calculations I perform assume that there is no change in interior temperatures as a result of the insulation. In fact, warmer surfaces and the reduction of drafts can result in equal comfort levels at lower temperatures, so the total effect of thermal conservation measures is likely to exceed that calculated below.

5.2 - Insulating the Building Shell

Q: What is the "building shell"?

A: The building shell is the portion of the structure which is responsible for isolating the conditioned space within the building from the unconditioned space outside. The important portions of the shell are the roof and top-floor ceiling; the walls, windows, and doors; and the foundation and the floor of the bottom conditioned floor. Heat may be lost through all of these surfaces by conduction, and through cracks in and between these surfaces, by infiltration.

Q: What fraction of heat loss would be due to each of these factors?

A: Northeast Utilities (1978) estimated that a conventionally insulated two-story house loses 8% of its heat through the ceiling, 30% through the walls, 4% through the floors and foundation, 24% through the windows, and a total of 34% due to infiltration.

Q: What is the cost of conservation from increased ceiling insulation levels?

A: Table 5.1 computes the cost per kWh saved for various thicknesses, for various climatic conditions. The optimal thickness (the point at which the savings from added insulation just equals its cost) is about 12 to 15 inches, depending on climate. The input values assumed are provided as notes to the table. The price of cellulose per pound is a current retail price; the actual cost will vary depending on how it is purchased, and then on the structure of the conservation program. Once the decision has been made to install or increase insulation, the additional labor and equipment costs for blowing a few more inches should be negligible. The limit on cost-effective insulation thus appears to be the space available in the attic, or the strength of the ceiling. Since no credit is assumed for tax credits, air conditioning energy savings, or space conditioning equipment costs (for new construction in particular) the tabulated costs of the various insulation levels are apt to be on the high side. It is clear from the table that "super insulation" of new construction (in colder areas, particularly) is cost-justified. Hence, MMWEC and its members should be encouraging much higher ceiling insulation levels, especially in new construction and in the colder portions of the state service territory, and if necessary, refusing service to electrically heated construction which has insulation levels well below optimal.

Q: Would similar insulation levels be cost-effective for building walls?

A: In general, yes. The structural issues involved in expanding existing walls or constructing new buildings with thicker walls are more complex to analyze, and I have not attempted to do so for this project. However, walls represent a much larger heat loss than ceilings (3 to 5 times as large, by the estimates of NU (1978)), so there is large conservation potential.

Q: How much energy could MMWEC save by increasing ceiling insulation in all electrically heated homes to the cost effective levels?

A: Assuming that half of the electrically-heated homes in MMWEC member service territories currently have ceiling insulation to R-21 and the other half to R-41, that heating degree-days average 6500, and that those homes are brought up to R-66.5, the average energy saving would be 1 kWh/year/sq. ft. of ceiling, or 1000 kWh/home for a 1000 square foot ceiling. If 5% (or about 10,000) of MMWEC member residential customers have electric space heat, 10,000 MWH annually could be saved from ceiling insulation alone, not counting commercial and industrial opportunities, which may be of the same magnitude.

Q: How can foundations be insulated?

A: Insulation can be added inside the building, sheet insulation can be added to the outside of exposed foundation (and perhaps a foot or so into the ground), and new foundations can be completely insulated with rigid or poured foam.

Q: Do you have any estimates of the cost-effectiveness of foundation insulation?

A: Based on utility estimates, Buchsbaum (1983) reports that insulating the sill plate (the boundary between the foundation and the frames) costs $36 and saves 180 kWh annually; if the insulation lasts 20 years, this is equivalent to 2.7 cents/kWh. Buchsbaum's data on energy savings is primarily from NU (1983), and therefore reflects heating loads in Connecticut. Savings will be larger in many MMWEC towns, which are colder than NU's service territory. Other foundation insulating opportunities are more site specific.

Q: How can heat losses through windows be reduced?

A: There are several such techniques, including

- the installation of additional glazing, including
    * conventional storm windows,
    * window panes with multiple layers of glass or other transparent material,
    * and temporary or permanent interior storm windows;
- the installation of movable rigid insulation, in the form of shutters; and

- the installation of movable flexible insulation, in the form of curtains or shades.

These approaches all involve simple technology, and are readily available. More exotic window technologies, including heat-selective surfaces which allow light in but are reflective to the infra-red radiation which would carry heat out of the building, are in various stages of development and commercialization, and may soon revolutionize the role of windows in energy efficiency. I will not consider these new techniques.

Q: Can you estimate the cost of insulating windows in existing buildings?

A: Yes. A typical window with a storm window would have an R value of about 1.8.[39] Approximate installed costs and incremental R-values for three add-on technologies are listed in Table 5.2.[40] The cost figures and R values are from Consumers Union (1982), except for the Window Quilt cost estimate, which is from a recent price quote. All costs are

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39. I assumed that all electrically heated homes already have storm windows; strangely enough, MMWEC does not seem to be convinced that even simple storm windows are always cost-effective (IR AG-G-44).

40. The shutter and interior storm assume some simple home-owner labor: costs would be somewhat higher for utility-installed systems or commercial and industrial applications which require additional labor (as opposed to utilizing slack time in maintenance schedules).

retail, and could probably be reduced in a utility conservation program.

Table 5.2 also computes the cost of this conservation in cents/kWh saved. Depending on the application, the shade and shutter would probably be open during part of the heating season: assuming that the average insulation would be in place for 75% of the heating degree days (which are concentrated in the nighttime hours), the cost of the conservation energy would increase by a third.

Even with only 75% utilization, installation of shutters on 10 windows, each 3x5 feet, would save some 2000 kWh annually in each electrically heated house.

Q: Can you estimate the cost of conservation through weatherstripping and infiltration control?

A: Yes. Table 5.3 lists six infiltration control measures, along with their energy savings and installed cost, from Buchsbaum (1983). The same Table computes the cost per kWh saved for 12% financing and useful lives of 5 years for weatherstripping and 10 years for caulking (which is likely to be an underestimate, since a good quality caulk will last twice that long). The savings figures are likely to be underestimates, and the costs per kWh overestimates, for the large parts of Massachusetts which are colder than Connecticut, since Buchsbaum's data is from NU. Installation of all of these measures (including 18 gaskets) would result in savings of more than 2500 kWh annually.

5.3 - Other Space Heating Conservation Techniques

Q: What other options are available for conservation of electricity used for space heating?

A: Some of the available techniques include:

- automatic setback thermostats;
- waste heat recovery, particularly in restaurant kitchens and industrial facilities, where heated air must be exhausted to the environment;[41]
- woodstove installation;
- heat pump installation; and
- solar space heating.

Q: Have you developed cost estimates for conservation energy from any of these sources?

A: Yes. Simple setback thermostats retail for less than $50. The associated savings depend on the usage patterns of the home or building (families in which all members are away from home during the day can realize the greatest savings, since the temperature can be set back for the greatest number of

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41. This waste heat can be used for space heating or water heating, depending on the situation.

hours), as well as the comfort level maintained in the home while it is occupied. Overall, 10% savings (or roughly 1000 kWh/year, before major conservation efforts) seem readily achievable, with no decrease in comfort while the residents are home and awake, and at costs below a penny per kWh. Lewis and Kohler (1981) computed a 15% usage reduction for a setback from 68 degrees to 60 degrees for just nine hours each night, for a house in Boston.

Adding a very efficient heat pump to a home that already has central air conditioning (and thus ductwork) can reduce energy consumption by 60% for about 9 cents/kWh; in a new home, where the incremental cost is reduced by the avoided investment in a resistance heating system, the cost is more like 3.7 cents/kWh. Neither of these figures includes any credit for replacing the air conditioner. These cost figures are derived in Table 5.14. Greater efficiencies can be achieved in heat pumps using ground water or low temperature solar systems as heat sources.

Woodstove savings also depend on usage, among other factors. However, a $1000 installation in which just one cord of wood is burned annually (replacing about 3500 kWh), costs about

4.2 cents per kWh saved, assuming a 15 year life.[42] The fuel would cost about 3 cents/kWh (at $100/cord) in 1985 in the Boston suburbs, and less in forested areas. Even including inflation in fuelwood prices, woodstoves should provide space heating at costs well below the cost of Seabrook power.

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42. Except for the stovepipe, the installation should last much longer than 15 years, but the shorter life allows for some maintenance costs.

5.4 - Hot Water Energy Conservation

Q: How can electricity used in water heaters be conserved?

A: There are several applicable techniques, including:

- reduction in water temperature,
- water heater tank insulation,
- pipe insulation,
- end use reduction, such as flow restrictors,
- heat pump water heaters,
- solar water heaters, and
- waste heat recovery.

Q: What does water heating energy conservation cost?

A: Table 5.4 lists several measures, with estimates of cost and effectiveness. The costs per kWh range from 0 to 5.3 cents/kWh saved, with all measures except pipe insulation below 1 cent/kWh. The listed estimate of the savings from pipe insulation may be low: New Shelter (1981) reports test results demonstrating savings up to four times as large, and this is confirmed by EOER (1979a).[43] Table 5.4 also displays the fraction of water heaters for which NU (1983) has found each of the three tank treatments (wrap at 140 degrees, wrap at 120 degrees, and lower temperature from 140 to 120 and wrap) applicable, and the weighted savings and cost.

Q: Do the tank insulation levels in Table 5.4 represent optimal levels?

A: No. The utility insulation wraps referred to in Table 5.4 are only about 2 inches thick, and only bring the total tank insulation level to about R12. Since the difference in temperature between the interior of the tank and the outside air averages between 50 degrees Farenheit (for a 120 degree tank in a 70 degree conditioned space) and 80 degrees (for a 140 degree tank in a 60 degree unconditioned basement space), the tank is exposed to a differential equivalent to 18,000 to 29,000 heating degree days, or up to twice the heat loss of a house in Nome. Yet standard tank wraps bring the insulation level to only about the thermal resistance of a conventional house wall.

Table 5.5 computes the cost of conservation from insulation of a hot water tank of moderate temperature differential and

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43. The EOER publication also indicates that savings can be much higher in industrial, commercial, and institutional applications.

internal insulation. At costs competitive with Seabrook power, up to 18 inches of external wrap is cost-effective, reducing energy losses by 850 kWh.

Q: What kinds of waste heat can be recovered for water heating?

A: In addition to the types considered in the previous section, for space heating conservation (cooking and industrial ventilation air heat recovery), water may be heated or preheated with the waste heat from refrigeration equipment, central air conditioning, and waste water.

Q: How much electricity can be conserved by converting from resistance electric water heating to heat pump water heating, and at what cost?

A: Table 5.14 presents these figures both for a new water heater with an integral heat pump and for an add-on heat pump with an existing tank. The add-on is both less expensive and less efficient than the new system (even when the new unit is credited with the avoided cost of a conventional water heater), so both units cost 4.4 cents per kWh saved. The integral unit saves about 4300 kWh annually, while the add-on saves 3900 kWh. If all the electric water heaters in the MMWEC towns were converted to heat pumps, about 200 GWH would be saved in the short term, and 300 GWH by the end of the century.[44]

The economics of heat pump water heating may be even better for larger installations. The Megatech ground-water source system which MMWEC described in response to IR AG-2-214, is said to save energy at about 0.5 cents/kWh: even if this cost result is understated by several times, this is inexpensive conservation.

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44. This calculation assumes that MMWEC's saturations are the same as NEPOOL's estimates for Massachusetts.

5.5 - Lighting Efficiency Improvements

Q: What kinds of lighting efficiency improvements are feasible?

A: There are several types of improvements which are possible, including:

- installation of occupancy sensors, so lights turn off when the room is unoccupied,
- installation of daylight sensors, so that lights turn off when daylighting is sufficient,
- addition of switches to allow selective use of lighting in non-residential settings,
- delamping, or reduction of background lighting levels, supplemented by task lighting as needed,
- conversion of incandescent lamps to fluorescents, either conventional tubes or new high-efficiency compact lamps,
- replacement of standard incandescent bulbs with high-efficiency models
- replacement of standard fluorescent tubes, and their ballasts, with high efficiency models, and
- conversion of streetlighting and of other large area to higher efficiency technologies, including mercury,

high-pressure sodium, and low-pressure sodium lamps.

Q: How much does it cost to save energy by converting from incandescents to fluorescents?

A: The simplest conversions are those which use screw-in replacement bulbs or fixtures. The established fluorescent technology for this purpose is a circular tube with a screw base and a conventional ballast (the "circlite" bulb). The emerging technology is a compact, bulb-like lamp containing a folded tube and an electronic ballast, which is more efficient than the circlite and which can be used in more applications. Table 5.6 derives the costs of replacing 100 W and 75 W incandescents with 44 W circlites (which produce about the same light as 100 W incandescents), and of replacing 60 W and 40 W incandescents with 22 W circlites (which produce about the same light as 60 W incandescents). Table 5.7 derives the costs of replacing 75 W, 60 W, and 40 W incandescents with compact fluorescents.[45] Both Tables indicate that conversions can be cost effective for lights used as little as an hour or two daily, and even where the replacement bulb produces substantially more light than the incandescent.

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45. Costs, useful lives, and light output are from Geller (1983) and retail inquiries.

The potential for conservation in residential lighting is considerable: if half of the residential lighting load (and thus considerably less than half the lamps) of MMWEC's members were doubled in efficiency (and some of the conversions discussed would quadruple efficiency), 72,600 MWH would be saved each year. The potential is probably greater in commercial and industrial lighting, but MMWEC does not present estimates of lighting loads in those sectors.

Q: How much does it cost to replace standard fluorescent ballasts with high-efficiency models?

A: Table 5.8 calculates those costs, both for situations in which a new ballast is required (new installations or replacement of defunct ballasts), and those in which the existing ballast is simply discarded in the middle of its useful life. The costs range from negative values to 12.2 cents/kWh. For the most common arrangement (two 40W lamps), the cost of energy from early replacement is only six cents/kWh.

Table 5.8 compares only standard and efficient wire-wound ballasts. The energy savings listed in that Table can be doubled through the use of solid-state ballasts (Naval Civil Engineering Laboratory, 1983), for which I have not yet obtained cost figures.

Q: How much does it cost to replace standard fluorescent tubes and incandescent bulbs with high-efficiency models?

A: Table 5.9 displays the cost, rated life, and energy savings for various size efficient incandescent bulbs; Table 5.10 repeats these calculations for fluorescent tubes.[46] The costs of these replacements range from negative values (the fixed costs of the efficient lamps are often lower than those of the standard lamps, due to the longer life of the former) to 3.6 cents per kWh saved, if the old lamp has burned out, or from negative values to 12.8 cents if the standard lamp is replaced in the middle of its life. The high-end costs in each case are for fluorescents which are used less than an hour a day, which are probably quite rare.

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46. The costs and lifetimes for the incandescents differ from those in earlier tables: for consistency, all values in Tables 5.9 and 5.10 are from the same source.

5.6 - Residential Appliance Efficiency

Q: What kinds of residential appliance efficiency improvements are possible?

A: In general, new appliances are more efficient than the existing stock of appliances, and the most efficient new appliances are still more efficient than the average of new shipments. The efficiency level of the overall stock can be improved by encouraging (or requiring) purchasers of new appliances to select a model from among the most efficient available, and by encouraging owners of older, inefficient models to retire thenm in favor of the most efficient new models. Table 5.14 computes the cost per kWh saved if MMWEC financed the total difference between the cost of the average recent unit and the most efficient recent unit, for water heaters, frost-free refrigerators, and freezers. (The other calculations in Table 5.14, for heat pumps and for add-on water heater heat pumps, have already been addressed.) The data is largely from Geller (1983) and ACEEE (1984). The Table also computes the potential energy savings from these efficiency improvements. Those calculations assume the accuracy of MMWEC's projections of efficiency improvements from the replacement of existing units with average new 1980/81 models: if MMWEC's projections of efficiency improvements are overstated, the costs of conservation would be lower, and the potential savings would be higher. Also, the efficiency savings from replacement of older units (both of the appliances listed in Table 5.14 and other appliance types) can be accelerated if MMWEC needs those savings sooner.

Q: Can any of these efficiency improvements be applied to existing appliances?

A: Some of these improvements are possible in existing equipment. Water heater insulation wraps and add-on heat pumps are examples of such appliance efficiency retrofit, as are addition of refrigerator and freezer anti-sweat switches, and of dishwasher cool-dry switches.

5.7 - Rate Design

Q: How can rate design promote 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 infra-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 most of MMWEC's members have declining block rates for most or all of the major rate classifications. Since municipal light plants can return over-collections to the municipality (for example, as in-lieu-of-tax payments), it is even easier for MMWEC's members to adopt marginal-cost pricing than it is for privately owned utilities. Table 5.11 tabulates some conservation-discouraging features in the rates of 18 MMWEC members: all had one or more promotional features.[47] Table 5.12a computes the extent of residential declining block structures for the usage levels provided in MMWEC (December 1983): declining blocks at higher levels, such as to encourage space heating, would not be detected by this analysis. Table 5.12b repeats this analysis for commercial rates, and Table 5.12c for industrial.

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. Yet many of MMWEC's members retain demand charges for large customers and apparently none of them have instituted mandatory time-of-use rates.

Many of MMWEC's members also offer lower, promotional rates for selected uses, especially residential heating, but also

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47. In some cases, the declining blocks are almost flat: none of these utilities uses increasing block structures to encourage efficient energy use.

on some commercial and industrial rates and sometimes for air conditioning, water heating, and other uses in electrically heated buildings. These rates simply increase the subsidy for these uses, which is undesirable for three reasons. First, end uses such as water heating and space heating, for which alternative energy sources exist, are probably more price sensitive than non-competitive uses such as lighting and motors, for which electricity can only be replaced by efficiency investments. Second, large efficiency improvements are possible in space conditioning and water heating, which will not be adequately pursued under promotional rates. For both these reasons, promotional space conditioning and water heating rates will tend to increase total electric use. Third, using electricity for space heating is very inefficient; about three times as much fossil fuel is used in heating a house electrically as would be necessary to heat the same house directly. For heating water, electricity uses between two and three times as much fuel as does direct firing. While there may be some advantage to burning #6 oil in utility boilers rather than #2 oil or natural gas on customers premises, it is not likely to exceed this sizable efficiency penalty. Therefore, the extra subsidies of electric heat and related uses which are offered MMWEC's members increase electric use in a particularly undesirable way.

Q: Do marginal energy charges actually affect energy use?

A: There is considerable evidence that they do. Practically speaking, it is difficult to understand why customers would respond to inframarginal charges which are beyond their control, or fail to respond to marginal charges which actually vary with consumption. The same point may be made in more elegant theoretical terms by defining the customer's objectives mathematically and determining the consumer's optimal level of electric consumption; only the marginal price of electricity will affect the rational consumer's actions.

Empirical evidence is rather sparse on this issue, but the small amount available supports the theory. Several researchers have used statistical methods to measure customers' response to marginal price and have found that this response is significant. These studies have estimated the elasticity of electric demand with respect to the marginal price of electricity by comparing electric use in areas with different marginal electric prices (cross-sectionally), by comparing electric use in one area as price changed over time (in a time series), or by combining cross-sectional and time-series data. A price elasticity is the percentage change in sales which is caused by a 1% increase in price. Thus, an elasticity near zero implies little price response, while an elasticity with a large absolute value implies considerable price response. Negative elasticities imply that increased prices decrease sales, which is the expected result. Customers do not react instantaneously to a price increase. It takes time to change habits, insulate, replace appliances and so on. Therefore, short-run price elasticities (measured within a few months or a year of a price change) will be much smaller than elasticities which measure price effects in the long-run (ten to fifteen years). Unless otherwise noted, the elasticities I discuss below are long-run elasticities.

Taylor, Blattenberger, and Verleger (1977) developed two sets of elasticity models. The flow-adjustment models indicated that the effects of intra-marginal charges are not statistically significant (p. 5-4; the t-ratios are less than 2.0), while the marginal-charge elasticity is significant and is about -0.8 if a logarithmic equation is used, to about -5 if a linear model is assumed (p. 5-9). For the appliance stock models, the intra-marginal charge coefficients in the intensity equations average 26% of the marginal charge coefficients. The appliance saturation equations are of very poor statistical quality, but even so the marginal price is generally more important thant the intra-marginal charge (pp. 6-7, 6-8). For all but two saturation equations, the fixed charge either has a positive sign (indicating that increased fixed charges <u>increase</u> saturation) or its coefficient is less significant that that of the marginal price. Combining the intensity and saturation equations, the authors develop marginal price elasticities for the appliance stock models of -0.46 to -0.90, with an average of -0.59. The appliance stock models are more ambitious than the flow-adjustment models and exhibit greater statistical problems, but they support the general result.

These results are also supported by a somewhat simplistic Boston Edison study (BECo, 1979), which found that residential kWh consumption is 75 times as sensitive to marginal price as to average price. The elasticity of use with respect to marginal price was calculated to be -0.0185; this is a very short-run elasticity, reflecting changes on the order of a few months, and is comparable to the short-run elasticities in Taylor, et al. (1977) linear flow-adjustment models of -0.06 to -0.12.

Other studies have simply estimated elasticities for marginal price, without attempting to include average price or fixed charges.

Houthakker, Verleger, and Sheehan (1974) derived long-run marginal-price elasticity estimates of -1.0, -1.2, and -0.45, depending on the approximation of marginal price which was used. Houthakker (1978) later used a different definition of marginal price to derive elasticities for the country, the Northeast, New England, and Massachusetts; the long-run marginal elasticities ranged from -1.423 for the United States to -0.673 for the Northeast, with -0.756 for Massachusetts. Halvorsen (1975, 1976) estimated the coefficient of marginal price in several different ways, resulting in elasticities of -0.974 to -1.21 for residential use, -0.916 to -1.208 for commercial use, and -1.242 to -1.404 for national industrial use, all at a high level of signifance (a result of -0.562 for commercial elasticity was less significant and was eliminated by the use of dummy variables for two states). Including the impacts of industrial location decisions, the statewide industrial elasticities would be -1.530 to -1.752.

Q: How large a conservation impact would be expected from changes in rage design?

A: In the long term (that is, over the next 10-15 years), the total sales in each rate schedule will be lower by the ratio of the new marginal price to the old marginal price, raised to the long-term elasticity, all other things being equal. Table 5.13 shows these results for a range of marginal price elasticities and a range of marginal (tail block) energy price increase. For some small customers, the marginal energy price may decrease, depending on whether total revenues are held constant. However, since the bulk of sales are to customers whose marginal price would increase, the overall impact should be to greatly increase conservation and reduce sales. In addition, the smaller customers probably have lower price elasticities, and their smaller price response would thuse not offset that of the larger customers.

5.8 - Other Conservation Options

Q: What other conservation techniques are there which do not fall in the categories you discussed above?

A: Some of the other options which can be applied on customer premises include:

- heating, ventilating, and air conditioning system efficiency improvements,
- shading and reflective windows to reduce air conditioning loads,
- motor efficiency improvements, and
- efficiency improvements in commercial[48] refrigerators and freezers, including addition of doors, improvement in gaskets, and control of anti-condensation heaters.

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

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

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48. This category would include groceries, wholesalers, restaurants, institutional food services, and the food processsing industry.

Q: What are the advantages of preventing new master-metering installations and converting existing installations to individual meters?

A: The master-metered electricity user essentially faces a zero price of energy, and therefore has no incentive to use it wisely. Any connection between the behavior of the master-metered user and the costs to that user is quite tenuous. Under direct utility metering, submetering (in which the building pays the utility, and the occupants are billed by the building), or check-metering (in which the building bill is simply apportioned to the occupants in proportion to their kWh consumption) the electricity consumer can save money by saving energy.

Consumers do seem to respond to direct metering. Federal Energy Administration figures (UCAN Manual of Conservation Measures, Conservation Paper #35) indicate that single-metered apartments use about 25% less energy than master-metered apartments.

It is not possible to calculate MMWEC's potential savings from the elimination of master metering, since I do not have information on the number and usage of master-metered apartments and businesses served by its members. It does not appear from MMWEC's discussion of conservation that it has collected such information itself, or studied the economics of converting these buildings to individual meters.

Of course, if electric rates were revised to eliminate the discounts for increased usage, 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: Voltage control consists of various techniques to reduce distribution circuit voltages, particularly in low-demand periods, from the higher end of the acceptable range of voltages to the lower end. Results to date indicate that these techniques are very attractive. In one study, American Electric Power 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. (Electrical World, 6/15/77, pp. 52-53). 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 GWH, and a fixed charge rate of 14.7 (a 12% cost of capital, for a 15 year life), we get a cost per kWh saved of 4.3 cents.

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 circuits; 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 0.4 to 1.2 cents. Southern California Edison (1984) reports voltage control savings of 1,775 GWH annually, or about 3% of SCE's sales. A recent summary (California Public Utilities Commission, 1983) reports that the California utilites are saving 180 GWH annually from voltage control, at a cost of 0.19 cents/kWh. These studies are included in Appendix I.

5.9 - Conclusions and Assessment

Q: Can you summarize the results of your analysis of conservation potential?

A: I can not add up potential in the same way that I did for alternative power supplies: my specific analyses have considered only a small fraction of conservation techniques, and some of the measures I did consider interact with one another. For example, installation of a heat pump reduces the conservation benefit of additional insulation, and both the heat pump and insulation reduce the benefit of a set-back thermostat. Nonetheless, it is clear that there are large amounts of conservation available in MMWEC's service territory at costs comparable to those of Seabrook, and often at much lower costs. If MMWEC's members, either through rate design, conservation subsidies, or other measures, increased the incentive to conserve by just 30% compared to current rates, they could reasonably be expected to achieve long term reductions in sales of 20% to 30%.

Q: How does this amount of conservation compare to MMWEC's projected capacity shortfall at the end of the century without Seabrook?

A: MMWEC projects a capacity shortfall of 492 MW for the base case forecast without Seabrook in 1999/2000. This projected shortfall is about 38% of MMWEC's projected requirement of 1295 MW. Even if MMWEC's base case forecast were correct, and even if NEPOOL reserve requirements were as large as MMWEC projects, conservation could be expected to eliminate 250 to 400 MW of the capacity deficiency currently projected, leaving only about 100 to 250 MW of resources to be met with new conventional and alternative power sources.

Q: Does this conclude your testimony?

A: Yes.

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7 - TABLES AND FIGURES

Figure 2.1: Power Cost Comparison

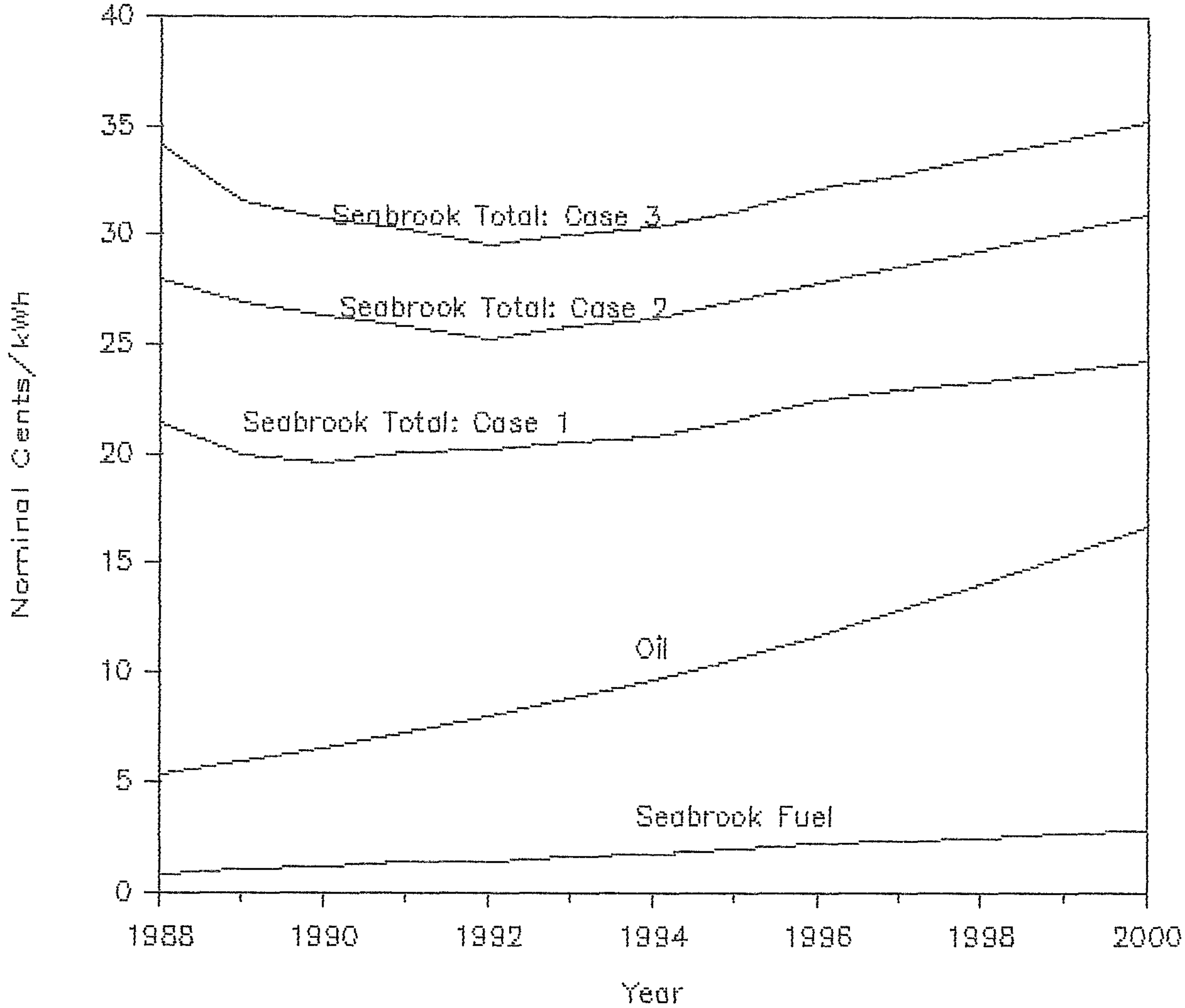

TABLE 2.1: Fuel and Power Costs, Nominal Cents per Kwh

	MMWEC Fuel Cost Projections			Seabrook Total Costs		
			Case:	1	2	3
			Operating - Characteristics:	MMWEC	PLC	PLC
Year	Seabrook	Oil [1]	Capital Cost:	$5.5 B	$6 B	$8 B
1988	0.9	5.41		21.4	28.0	34.2
1989	1.0	5.94		20.0	26.9	31.7
1990	1.2	6.53		19.7	26.3	30.8
1991	1.4	7.23		20.1	25.9	30.3
1992	1.4	8.03		20.2	25.3	29.5
1993	1.6	8.87		20.6	25.8	30.0
1994	1.8	9.68		20.8	26.3	30.4
1995	2.0	10.61		21.5	27.0	31.1
1996	2.2	11.67		22.5	27.9	32.2
1997	2.4	12.88		22.9	28.6	32.9
1998	2.5	14.08		23.4	29.4	33.6
1999	2.7	15.39		23.8	30.2	34.4
2000	2.9	16.71		24.3	31.0	35.3

NOTES: [1] MMWEC Base Fuel Forecast, 1% #6 Oil at 10,000 BTU/kwh, Exh. RMC-12, page 3.

Table 2.2: Seabrook Costs (Cents/Kwh)

Year	Case 1		Case 2		Case 3	
	Total	Net	Total	Net	Total	Net
1988	21.4	10.0	28.0	14.5	34.2	20.6
1989	20.0	7.7	26.9	11.9	31.7	16.7
1990	19.7	7.9	26.3	12.0	30.8	16.5
1991	20.1	8.5	25.9	12.3	30.3	16.7
1992	20.2	8.8	25.3	12.3	29.5	16.5
1993	20.6	9.1	25.8	12.8	30.0	17.0
1994	20.8	9.5	26.3	13.4	30.4	17.5
1995	21.5	10.3	27.0	14.2	31.1	18.3
1996	22.5	11.2	27.9	15.1	32.2	19.4
1997	22.9	11.6	28.6	15.8	32.9	20.1
1998	23.4	12.1	29.4	16.5	33.6	20.8
1999	23.8	12.5	30.2	17.3	34.4	21.6
2000	24.3	13.0	31.0	18.2	35.3	22.4
2001	24.8	13.5	31.9	19.1	36.2	23.3
2002	25.3	14.0	32.9	20.1	37.1	24.3
2003	25.9	14.6	33.9	21.1	38.1	25.3
2004	26.5	15.2	35.0	22.2	39.3	26.4
2005	27.1	15.9	36.2	23.4	40.5	27.6
2006	27.8	16.5	37.5	24.7	41.7	28.9
2007	28.6	17.3	38.9	26.1	43.1	30.3
2008	29.3	18.0	40.4	27.6	44.6	31.8
2009	30.2	18.9	42.0	29.2	46.2	33.4
2010	31.1	19.8	43.7	30.9	47.9	35.1
2011	32.0	20.7	45.6	32.7	49.8	37.0
2012	33.0	21.7	47.5	34.7	51.8	39.0
Levelized [2]:						
1988-2002	21.4	9.9	27.5	14.1	32.1	18.6
1988-2012	22.4	11.0	29.2	15.8	33.7	20.3

Notes: [1] Net of Case 4 Costs.

[2] Levelized at 11.0%.

[3] All results from Appendix B.

TABLE 2.3: 1988 Seabrook Rate Effects, as Percentage Increases from 1983 Rates

Member	MW of Seabrook	1983 Revenues	Case 1	Case 2	Case 3	Case 4
Total MMWEC Seabrook share	131.45		$105,441,000	$127,307,000	$162,814,000	$78,384,000
Total for member participants	118.57	$241,517,455	39%	48%	61%	29%
Ashburnham	0.65	$1,382,952	38%	46%	58%	28%
Boylston	0.87	$1,379,309	51%	61%	78%	38%
Braintree	7.05	$22,677,771	25%	30%	38%	19%
Danvers	10.99	$15,892,242	55%	67%	86%	41%
Georgetown	0.96	$1,518,331	51%	61%	78%	38%
Groton	1.27	$2,323,436	44%	53%	68%	33%
Hingham	4.74	$8,748,891	43%	52%	67%	32%
Holden	3.95	$5,208,417	61%	73%	94%	45%
Holyoke	3.43	$20,641,688	13%	16%	21%	10%
Hudson	16.26 [1]	$9,408,328	139%	167%	214%	103%
Hull	1.64	$2,781,293 [2]	47%	57%	73%	35%
Ipswich	1.19	$5,299,767	18%	22%	28%	13%
Littleton	1.22	$5,089,073	19%	23%	30%	14%
Mansfield	7.88	$10,667,318	59%	72%	92%	44%
Marblehead	1.48	$6,078,730	20%	24%	30%	15%
Middleboro	5.46	$7,265,227	60%	73%	93%	45%
Middleton	3.22	$3,131,385	82%	99%	127%	61%
North Attleboro	3.92	$8,132,968	39%	47%	60%	29%
Paxton	0.81	$1,245,940	52%	63%	80%	39%
Peabody	10.69	$21,919,961	39%	47%	60%	29%
Reading	7.03	$32,197,107	18%	21%	27%	13%
Shrewsbury	5.83	$8,905,471	53%	63%	81%	39%
South Hadley	3.93	$6,298,979	50%	60%	77%	37%
Sterling	2.23	$1,898,497	94%	114%	145%	70%
Templeton	1.91	$4,257,386	36%	43%	56%	27%
Wakefield	3.94	$9,149,166	35%	42%	53%	26%
West Boylston	1.96	$2,976,117	53%	64%	82%	39%
Westfield	4.06	$15,041,705	22%	26%	33%	16%

NOTES: 1) Hudson owns 0.915 MW directly.

2) These are 1982 revenues. The 1983 revenues were not available in our data.

TABLE 2.4: Effects of Seabrook Rate Increases on Long-Run Sales

	Rate Increase				Long-Run Reduction in Sales if Price Elasticity = -0.5				Long-Run Reduction in Sales if Price Elasticity = -1.0			
Case Number	1	2	3	4	1	2	3	4	1	2	3	4
Member												
Total for member participants	39%	48%	61%	29%	15%	18%	21%	12%	28%	32%	38%	23%
Ashburnham	38%	46%	58%	28%	15%	17%	21%	12%	27%	31%	37%	22%
Boylston	51%	61%	78%	38%	19%	21%	25%	15%	34%	38%	44%	27%
Braintree	25%	30%	38%	19%	11%	12%	15%	8%	20%	23%	28%	16%
Danvers	55%	67%	86%	41%	20%	23%	27%	16%	36%	40%	46%	29%
Georgetown	51%	61%	78%	38%	19%	21%	25%	15%	34%	38%	44%	27%
Groton	44%	53%	68%	33%	17%	19%	23%	13%	30%	35%	40%	25%
Hingham	43%	52%	67%	32%	17%	19%	23%	13%	30%	34%	40%	24%
Holden	61%	73%	94%	45%	21%	24%	28%	17%	38%	42%	48%	31%
Holyoke	13%	16%	21%	10%	6%	7%	9%	5%	12%	14%	17%	9%
Hudson	139%	167%	214%	103%	35%	39%	44%	30%	58%	63%	68%	51%
Hull	47%	57%	73%	35%	18%	20%	24%	14%	32%	36%	42%	26%
Ipswich	18%	22%	28%	13%	8%	9%	12%	6%	15%	18%	22%	12%
Littleton	19%	23%	30%	14%	8%	10%	12%	6%	16%	19%	23%	13%
Mansfield	59%	72%	92%	44%	21%	24%	28%	17%	37%	42%	48%	31%
Marblehead	20%	24%	30%	15%	9%	10%	12%	7%	16%	19%	23%	13%
Middleboro	60%	73%	93%	45%	21%	24%	28%	17%	38%	42%	48%	31%
Middleton	82%	99%	127%	61%	26%	29%	34%	21%	45%	50%	56%	38%
N. Attleboro	39%	47%	60%	29%	15%	17%	21%	12%	28%	32%	37%	22%
Paxton	52%	63%	80%	39%	19%	22%	26%	15%	34%	39%	45%	28%
Peabody	39%	47%	60%	29%	15%	18%	21%	12%	28%	32%	38%	23%
Reading	18%	21%	27%	13%	8%	9%	11%	6%	15%	17%	21%	12%
Shrewsbury	53%	63%	81%	39%	19%	22%	26%	15%	34%	39%	45%	28%
South Hadley	50%	60%	77%	37%	18%	21%	25%	15%	33%	38%	44%	27%
Sterling	94%	114%	145%	70%	28%	32%	36%	23%	48%	53%	59%	41%
Templeton	36%	43%	56%	27%	14%	16%	20%	11%	26%	30%	36%	21%
Wakefield	35%	42%	53%	26%	14%	16%	19%	11%	26%	29%	35%	20%
W. Boylston	53%	64%	82%	39%	19%	22%	26%	15%	35%	39%	45%	28%
Westfield	22%	26%	33%	16%	9%	11%	13%	7%	18%	21%	25%	14%

TABLE 3.1: Seabrook Load Carrying Capacity

Power Year	MMWEC's Assumed NEPOOL Reserve Levels (%) [1] With Seabrook	Without Seabrook	NEPOOL Forecast Peak [2]	Seabrook Effective Load Carrying Capacity [3]	Seabrook ELCC/MW
	(A)	(B)	(C)	(D)	(E)
1989/90	28.40%	25.80%	17537	540.53	47.0%
1990/91	31.50%	29.70%	17986	628.33	54.6%
1991/92	29.10%	27.10%	18446	605.02	52.6%
1992/93	28.30%	26.20%	18962	585.97	51.0%
1993/94	26.90%	24.90%	19377	600.84	52.2%
1994/95	27.00%	25.00%	19900	592.13	51.5%
1995/96	30.80%	29.00%	20458	597.67	52.0%
1996/97	31.30%	29.70%	20975	620.26	53.9%
1997/98	30.80%	29.20%	21292	618.75	53.8%
1998/99	29.00%	27.50%	21471	641.81	55.8%
1999/00	29.90%	27.30%	21698	451.00	39.2%

NOTES:
1) From MMWEC Exhibit RMC-23.
2) From NEPOOL (1984).
3) (C*(1+B)+1150)/(1+A) - C

TABLE 4.1: Busbar Costs for Municipally Financed Wind Turbines (Cents/Kwh)

Mean Annual Wind Speed (mph)	Fixed Charge Rate		
	22% [1]	17% [1]	13.4% [2]
14	22.5	18.7	16.0
15.4	18.3	15.2	13.0
16.5	15.9	13.2	11.3
19	12.2	10.2	8.8

NOTES: [1] From Vachon (1984), Table 6 for Enertech 44/40.

[2] Extrapolated from previous columns.

Table 4.2: Levelized Cost of Power from McNeil Wood Plant
Cents per kWh

Year	Fuel	Composite
1988	4.41	8.75
1989	4.72	9.11
1990	5.05	9.50
1991	5.41	9.91
1992	5.79	10.35
1993	6.19	10.83
1994	6.62	11.34
1995	7.09	11.88
1996	7.58	12.46
1997	8.12	13.09
1998	8.68	13.75
1999	9.29	14.47
2000	9.94	15.24
Levelized at 11.0%	6.20	10.85

Source: All data from Exhibit RMC-31.

TABLE 4.3: Costs of Cogenerating Power, Net of Power Generated at Conventional Running Cost, in Cents/Kwh

Capital Cost ($/kw)	Heat Rates as Percent of Conventional Heat Rate		
	60%	50%	40%
250	1.4	1.2	1.0
400	2.1	1.7	1.5
500	2.6	2.1	1.8
600	3.1	2.5	2.1
800	4.0	3.3	2.7
1000	5.0	4.0	3.4
1500	7.4	5.9	5.0

Assumptions:

80% capacity factor

13.4% carrying charge (20 year life)

0.2 cents/kwh O&M

TABLE 4.4: Alternative Energy Potential

Energy Source	MW Potential: Mass.	MW Potential: Other New England	Typical Capacity Factor	Cost Range (cents/kwh)
Wind	85+		25-30%	9+
Hydro	43-100	1000	55%	9-13
Wood	80-120		75-80%	9-11
Solid Waste	75+		60%	11-13
Cogeneration	1000+	2419+	40-80%	1-10
Total:	1283 - 1380+	3419		
Average:			50-60%	

Table 5.1: Cost of Conservation from Added Ceiling Insulation, in Cents/kwh.

Cost of Cellulose: 21 cents/lb. Density: 2.6 lb/cu. ft.

R value: 3.5 /inch Effective cost = 1.3 cents/R-sq.ft.

Finance Rate: 12% Annual cost = 0.16 cents/R-sq.ft.-yr.

			Heating Degree Days				
From R=	To R=	inches=	5500	6000	6500	7000	7500
21	24.5	1.0	2.1	1.9	1.8	1.6	1.5
24.5	28	2.0	2.8	2.6	2.4	2.2	2.0
28	31.5	3.0	3.6	3.3	3.0	2.8	2.6
31.5	35	4.0	4.5	4.1	3.8	3.5	3.3
35	38.5	5.0	5.5	5.0	4.6	4.3	4.0
38.5	42	6.0	6.6	6.0	5.6	5.2	4.8
42	45.5	7.0	7.8	7.1	6.6	6.1	5.7
45.5	49	8.0	9.1	8.3	7.7	7.1	6.7
49	52.5	9.0	10.5	9.6	8.9	8.2	7.7
52.5	56	10.0	12.0	11.0	10.1	9.4	8.8
56	59.5	11.0	13.6	12.4	11.5	10.7	9.9
59.5	63	12.0	15.3	14.0	12.9	12.0	11.2
63	66.5	13.0	17.1	15.6	14.4	13.4	12.5
66.5	70	14.0	19.0	17.4	16.0	14.9	13.9
70	73.5	15.0	20.9	19.2	17.7	16.5	15.4
73.5	77	16.0	23.0	21.1	19.5	18.1	16.9
77	80.5	17.0	25.2	23.1	21.4	19.8	18.5
80.5	84	18.0	27.5	25.2	23.3	21.6	20.2
84	87.5	19.0	29.9	27.4	25.3	23.5	21.9
87.5	91	20.0	32.4	29.7	27.4	25.5	23.8
91	94.5	21.0	35.0	32.1	29.6	27.5	25.7

Assumes:

R value of ceiling = 2
R value of existing insulation = 19 (6 inches fiberglass)

Ignores effect of framing: since framing reduces the overall R of the first 6-8 of insulation, this assumption understates the value of added insulation.

Ignores air conditioning and equipment sizing benefits. Ignores tax credits.

TABLE 5.2: Cost of Window Insulations

Technology	Cost/sq.ft.	R	Heat Loss(kwh/sq.ft.-year) Heating Degree Days 5500	6000	6500	7000	7500
Storm Window	----	1.8	21.5	23.4	25.4	27.3	29.3
Window Quilt (Insulated Shade)	$6.70	2.5	9.0	9.8	10.6	11.4	12.3
Shutter	$2.70	4.5	6.1	6.7	7.3	7.8	8.4
Interior Storm Window	$0.70	1.1	13.3	14.5	15.8	17.0	18.2

	Useful life (years)	Cents/kwh Saved Heating Degree Days 5500	6000	6500	7000	7500
Window Quilt (Insulated Shade)	10	9.5	8.7	8.0	7.5	7.0
Shutter	10	3.1	2.9	2.6	2.4	2.3
Interior Storm Window	5	2.4	2.2	2.0	1.9	1.7

NOTE: Finance Cost = 12%

TABLE 5.3: Cost Estimates for Infiltration Control

Measure	Annual Kwh Savings [1]	Estimated Installation Cost [1]	Cost per Kwh Saved (cents) [2]
Caulking (10 windows, 2 doors)	936	90	1.70
Weatherstrip (10 windows, 2 doors)	936	90	1.70
Doorsweeps (2 doors)	210	17.5	2.31
Attic hatchway insulation	39	3.5	2.49
Outlet & switch gaskets (6 gaskets)	174	3	0.48
Air conditioner cover	42	6	3.96

NOTES: [1] From Buchsbaum (1983)

[2] Assumes 12% financing,
10 year life for caulking,
and 5 years for other measures.

TABLE 5.4: Cost Estimates for Water Heating Conservation

Measure	Annual Kwh Savings	Estimated Installation Cost [1]	Cost per Kwh Saved (cents) [2]	% of Water Heaters [3]
Tank Wraps				
Wrap tank at 140 F	773	32	0.73	41%
Wrap and turn down	1216	32	0.47	30%
Wrap tank at 120 F	574	32	0.99	29%
	----		----	
Weighted average tank wraps	848		0.73	
Drain sediment from tank	200	--	0	
Install low flow showerhead	426	8	0.33	
Faucet aerators (2)	214	7	0.58	
Pipe insulation hot water (20 feet)	40	12	5.31	

NOTES: [1] From Buchsbaum (1983)

[2] Finance Rate = 12%.
Assumes life of 10 years for these measures.

[3] From NU (1983)

TABLE 5.5: Calculation of Cost of Water Heater Insulation

R(0) = 6

r(0) = 12 inches

h(0) = 60 inches

DT = 70 degrees F

Finance Rate = 12%

Cost of fiberglass = 46 cents/cu.ft.

A(0) = 34.54 sq. ft.

R value for fiberglass = 3.2 /inch

Losses at R(0) = 1034.28

Life of insulation = 10 years

Cost of fiber-glass/year = 8.14 cents/cu.ft.-yr.

Added fiberglass (inches)		Surface Area (A) (sq.ft.)		Effective R		Annual Losses		Incremental Annual Cost	Cents/Kwh Saved
From (a)	To (b)	(a)	(b)	Incremental	Total	Total	Incremental		
0	3	34.5	46.1	7.2	13.2	470	-564	$0.70	0.12
3	6	46.1	58.9	5.6	18.8	330	-141	$0.94	0.67
6	9	58.9	72.8	4.6	23.4	265	-64	$1.20	1.87
9	12	72.8	87.9	3.8	27.1	229	-37	$1.48	4.02
12	15	87.9	104.2	3.2	30.3	205	-24	$1.79	7.46
15	18	104.	121.7	2.7	33.1	188	-17	$2.12	12.57

Table 5.6: Cost per kWh Saved from Lighting Improvements
(22 W circlite and 44 W circlite)

22 W Circlite

Replacement Bulb Wattage:	22	Cost:	$16.00	Life:	12000 hours
Standard Bulb:		Cost:	$0.50	Life:	750 hours
Finance Rate:	12%				

Annual Charges		Hours Use Per Year					
		300	500	1000	2000	2500	3000
	New Bulb	$1.94	$2.06	$2.58	$3.89	$4.58	$5.27
	Bulb Savings	$0.20	$0.33	$0.67	$1.33	$1.67	$2.00
	Net Cost	$1.74	$1.72	$1.92	$2.56	$2.91	$3.27
Standard Bulb Wattage:	**Savings (watts)**						
40	18	$0.322	$0.191	$0.106	$0.071	$0.065	$0.061
60	38	$0.153	$0.091	$0.050	$0.034	$0.031	$0.029

44 W Circlite

Replacement Bulb Wattage:	44	Cost:	$20.00	Life:	7500 hours
Standard Bulb:		Cost:	$0.50	Life:	750 hours
Finance Rate:	12%				

Annual Charges		Hours Use Per Year					
		300	500	1000	2000	2500	3000
	New Bulb	$2.55	$2.94	$4.19	$6.93	$8.33	$9.73
	Bulb Savings	$0.20	$0.33	$0.67	$1.33	$1.67	$2.00
	Net Cost	$2.35	$2.60	$3.52	$5.60	$6.66	$7.73
Standard Bulb Wattage:	**Savings (watts)**						
75	53	$0.148	$0.098	$0.067	$0.053	$0.050	$0.049
100	78	$0.100	$0.067	$0.045	$0.036	$0.034	$0.033

Table 5.7: Cost per kWh Saved from Lighting Improvements
(18 W compact flourescent)

Replacement Bulb Wattage:	18	Cost:	$18.00	Life:	7500 hours	
Standard Bulb:		Cost:	$0.50	Life:	750 hours	
Finance Rate:	12%					

Annual Charges		Hours Use Per Year					
		300	500	1000	2000	2500	3000
	New Bulb	$2.29	$2.64	$3.77	$6.24	$7.49	$8.75
	Bulb Savings	$0.20	$0.33	$0.67	$1.33	$1.67	$2.00
	Net Cost	$2.09	$2.31	$3.11	$4.91	$5.83	$6.75
Standard Bulb Wattage:	Savings (watts)						
40	22	$0.317	$0.210	$0.141	$0.111	$0.106	$0.102
60	42	$0.166	$0.110	$0.074	$0.058	$0.056	$0.054
75	57	$0.123	$0.081	$0.054	$0.043	$0.041	$0.040

Table 5.8: Cost of Conservation From Fluorescent Ballasts

Tubes			Cost	Life	Annual Cost	Annual Kwh Savings	Cost of Savings Cents/ Kwh
1 40W	Efficient		$14.70	20	$1.97		
	Regular		$13.20	10	$2.34		
	Net Cost	(New ballast required)			($0.37)	13.5	-2.73
		(Regular ballast replaced) [1]			$1.65	13.5	12.23
2 40W	Efficient		$14.70	20	$1.97		
	Regular		$13.20	10	$2.34		
	Net Cost	(New ballast required)			($0.37)	27	-1.36
		(Regular ballast replaced) [1]			$1.65	27	6.12
2 75W	Efficient		$29.00	20	$3.88		
	Regular		$25.00	10	$4.42		
	Net Cost	(New ballast required)			($0.54)	70	-0.77
		(Regular ballast replaced) [1]			$3.26	70	4.65

Notes: From The California Energy Commission (1982) for Most Probable case.

Finance cost: 12%

[1] Assumes half of useful life left.

Table 5.9: Cost of Energy Conservation from Upgrading within Lighting Technologies

Replacing Incandescent Lamps

Regular Lamps	Standard Lamp Cost	Standard Lamp Life	Replacement Lamp Cost	Replacement Lamp Life	Watts Saved Per Lamp		Cost of Conservation (Cents/Kwh) hrs/year: 300	500	1000	2000	3000
40 W	$0.75	1500 hrs	$1.09	2500 hrs	4 W	(1):	0.5	-0.5	-1.1	-1.4	-1.5
						(2):	9.2	7.3	6.1	5.5	5.3
60 W	$0.75	1000	$1.09	2500	6 W	(1):	-4.0	-4.7	-5.2	-5.4	-5.4
						(2):	3.9	2.7	1.8	1.4	1.3
75 W	$0.75	750	$1.09	2500	6 W	(1):	-8.4	-9.1	-9.6	-9.8	-9.8
						(2):	1.8	0.5	-0.4	-0.8	-0.9
100 W	$0.75	750	$1.09	2500	7 W	(1):	-7.2	-7.8	-8.2	-8.4	-8.4
						(2):	1.5	0.4	-0.3	-0.7	-0.8
Flood Lamps											
150 R/FL	$3.70	2000	$4.50	2000	75 W	(1):	0.8	0.7	0.6	0.6	0.6
						(2):	2.7	2.3	2.1	2.0	1.9
300 R/FL	$5.30	2000	$4.85	2000	180 W	(1):	-0.2	-0.2	-0.1	-0.1	-0.1
						(2):	0.9	0.8	0.7	0.7	0.7

Notes: (1) Cost of New Lamp
(2) Cost of Replacing Regular Lamp, assuming original bulb has 50% of original life remaining.

Finance Rate 12.0%

Data from EDER (1979b)

Table 5.10: Cost of Energy Conservation from Upgrading within Lighting Technologies

Replacing Fluorescent Lamps

Regular Lamps	Standard Lamp Cost	Standard Lamp Life	Replacement Lamp Cost	Replacement Lamp Life	Watts Saved Per Lamp		Cost of Conservation (Cents/Kwh) hrs/year: 300	500	1000	2000	3000
F40CW	$2.30	20000	$2.75	20000	5 W	(1):	3.6	2.2	1.2	0.8	0.7
						(2):	12.8	7.8	4.3	2.8	2.4
F96T12/CW	$5.35	12000	$5.50	12000	15 W	(1):	0.4	0.3	0.2	0.1	0.1
						(2):	7.6	4.8	3.0	2.3	2.1
F96T12CW/HO	$6.20	12000	$6.40	12000	15 W	(1):	0.5	0.3	0.2	0.2	0.1
						(2):	8.9	5.7	3.6	2.7	2.4

Notes: (1) Cost of New Lamp
(2) Cost of Replacing Regular Lamp, assuming original bulb has 50% of original life remaining.

Finance Rate 12.0%

Data from EDER (1979b)

Table 5.11 MMWEC Member Rate Design

	RESIDENTIAL			COMMERCIAL		
	Res. Declin. Block	Lower ESH Rate	Lower EWH Rate	Small Comm Decln Block	Large Comm Decln Block	Lower All Elctric or ESH Rate
Braintree	x		x	x	x	[1]
Chicopee	x	x	x	x	x	
Hingham	x	[1]	x	[2]	x	
Holden	x	x	x	x	x	
Holyoke	x		x	x	x	x
Hudson	x	x	x	x	x	x
Ipswich	x	x	x	x	x	[1]
Littleton			x			
Mansfield	x	[1]		x	x	x
Marblehead	x		x	x	x	x
Middleborough	x	x	x	x	x	
N. Attleborough	x	x	x			
Peabody	[2]			x	x	
Reading	x		x	x	x	
Shrewsbury	x		x	x	x	x
S. Hadley	x	x	x	x	x	
Wakefield	x		x	x	x	
Westfield	x			x	x	x

Source: Rate Schedule included in the Municipal's Returns to the DPU for the Year Ended December 31, 1984.

Notes: [1] Rate structure for this purpose differs from that of alternative rate so costs are not directly comparable.

[2] Tail block begins at 110 kwh or less.

Table 5.12a: Declining Blocks in MMWEC Member's Residential Electric Bills

Town	Bills for:			Cents/kwh		Decrease in Second Block
	100 kwh (a)	250 kwh (b)	500 kwh (c)	100-25 [2]	250-500 [3]	[4]
Ashburnham	12.46	26.42	49.12	9.31	9.08	2.4%
Boylston	12.16	24.81	44.26	8.43	7.78	7.7%
Braintree	9.03	21.03	39.00	8.00	7.19	10.2%
Danvers	12.85	26.59	46.67	9.16	8.03	12.3%
Georgetown	13.91	27.75	47.69	9.23	7.98	13.6%
Groton	11.68	25.95	48.75	9.51	9.12	4.1%
Hingham	11.63	24.71	46.01	8.72	8.52	2.3%
Holden	12.20	26.64	49.06	9.63	8.97	6.8%
Holyoke	10.81	23.25	43.16	8.29	7.96	4.0%
Hudson	9.49	21.40	40.12	7.94	7.49	5.7%
Hull	14.15	27.07	48.59	8.61	8.61	0.1%
Ipswich	10.74	23.03	41.68	8.19	7.46	9.0%
Littletn [1]	6.25	26.63	42.25	13.59	6.25	54.0%
Mansfield	11.22	23.21	41.34	7.99	7.25	9.3%
Marblehead	9.52	21.69	41.96	8.11	8.11	0.1%
Middleboro	15.60	28.58	48.65	8.65	8.03	7.2%
Middleton	9.79	21.44	39.81	7.77	7.35	5.4%
N. Attleboro	9.50	23.75	44.25	9.50	8.20	13.7%
Paxton	11.60	28.10	53.60	11.00	10.20	7.3%
Peabody	10.88	22.24	41.18	7.57	7.58	.0%
Reading	10.87	24.22	43.23	8.90	7.60	14.6%
Shrewsbury	9.50	20.93	38.05	7.62	6.85	10.1%
South Hadley	11.87	24.19	44.71	8.21	8.21	0.1%
Sterling	9.83	23.37	45.92	9.03	9.02	0.1%
Templeton	10.60	24.25	43.80	9.10	7.82	14.1%
Wakefield	11.58	24.18	44.39	8.40	8.08	3.8%
W. Boylston	7.91	18.84	35.07	7.29	6.49	10.9%
Westfield	8.40	18.66	35.74	6.84	6.83	0.1%

[1] Littleton's 100-250 kwh block includes a customer charge.
[2] b-a/1.5
[3] c-b/2
[4] 1-([3]/[2])

Table 5.12b: Declining Blocks in MMWEC Member's Commercial Electric Bills

Town	Bills For: 12 kw 1500 kwh (d)	30 kw 6000 kwh (e)	40 kw 10000 kwh (f)	Cents/kwh 1500- -6000 [1]	6000- 10000 [2]	Decrease in Second Block [3]
Ashburnham	171.06	594.42	952.62	9.41	8.96	4.8%
Boylston	167.93	566.58	905.05	8.86	8.46	4.5%
Braintree	121.04	472.80	778.28	7.82	7.64	2.3%
Danvers	166.15	622.53	1014.18	10.14	9.79	3.5%
Georgetown	164.14	688.90	1035.40	11.66	8.66	25.7%
Groton	164.30	586.43	957.69	9.38	9.28	1.1%
Hingham	139.15	545.11	905.96	9.02	9.02	.0%
Holden	155.10	562.69	921.38	9.06	8.97	1.0%
Holyoke	146.20	540.27	874.71	8.76	8.36	4.5%
Hudson	150.26	510.56	818.30	8.01	7.69	3.9%
Hull	173.45	605.00	985.40	9.59	9.51	0.8%
Ipswich	165.30	532.85	827.85	8.17	7.38	9.7%
Littletn	179.21	557.45	861.33	8.41	7.60	9.6%
Mansfield	146.37	487.70	752.60	7.59	6.62	12.7%
Marblehead	148.65	573.60	885.00	9.44	7.79	17.6%
Middleboro	143.56	551.71	914.51	9.07	9.07	.0%
Middleton	136.50	507.75	779.50	8.25	6.79	17.7%
N. Attleboro	151.10	598.40	903.00	9.94	7.62	23.4%
Paxton	184.70	675.20	1090.20	10.90	10.38	4.8%
Peabody	142.30	549.30	911.08	9.04	9.04	.0%
Reading	154.52	546.93	873.94	8.72	8.18	6.2%
Shrewsbury	127.31	468.73	758.72	7.59	7.25	4.4%
South Hadley	120.52	461.66	764.89	7.58	7.58	.0%
Sterling	146.97	487.92	774.70	7.58	7.17	5.4%
Templeton	119.80	464.50	755.90	7.66	7.29	4.9%
Wakefield	175.91	584.62	919.81	9.08	8.38	7.7%
W. Boylston	114.70	475.33	746.13	8.01	6.77	15.5%
Westfield	127.86	445.11	711.27	7.05	6.65	5.6%

[1] e-d/45
[2] f-e/40
[3] 1-([2]/[1])

Table 5.12c: Declining Blocks in MMWEC Member's Industrial Electric Bills

Town	Bills for: 30 mwh (g)	60 mwh (h)	200 mwh (i)	Cents/kwh 30-60 [1]	60-200 [2]	Decrease in Second Block [3]
Ashburnham	2836.32	5573.82	17928.82	9.12	8.83	3.3%
Boylston	2676.23	5293.29	17506.23	8.72	8.72	.0%
Braintree	2299.96	4599.96	15333.06	7.67	7.67	.0%
Danvers	2852.14	5676.34	18700.94	9.41	9.30	1.2%
Georgetown	3063.40	6052.90	20003.90	9.96	9.97	.0%
Groton	2761.79	5467.94	18096.64	9.02	9.02	.0%
Hingham	2557.89	5088.78	16899.60	8.44	8.44	0.0%
Holden	3161.00	5988.78	18258.83	9.43	8.76	7.0%
Holyoke	2404.30	4234.50	13900.50	6.10	6.90	-13.2%
Hudson	2365.73	4629.23	14600.03	7.54	7.12	5.6%
Hull	3587.40	7010.10	22636.20	11.41	11.16	2.2%
Ipswich	2455.85	4822.85	15448.85	7.89	7.59	3.8%
Littlton	2704.04	5387.27	17909.03	8.94	8.94	.0%
Mansfield	2069.19	4056.69	12883.69	6.63	6.31	4.8%
Marblehead	2532.00	4860.00	15724.00	7.76	7.76	0.0%
Middleboro	2554.10	4933.10	16053.11	7.93	7.94	-0.2%
Middleton	2513.25	5026.50	16755.00	8.38	8.38	0.0%
N. Attleboro	2876.50	5713.00	18950.00	9.46	9.46	0.0%
Paxton	3365.20	6700.20	22170.20	11.12	11.05	0.6%
Peabody	2726.10	5324.70	17375.00	8.66	8.61	0.6%
Reading	2645.79	5229.24	16617.49	8.61	8.13	5.5%
Shrewsbury	2174.16	4207.32	13525.40	6.78	6.66	1.8%
South Hadley	2310.81	4504.05	14459.18	7.31	7.11	2.7%
Sterling	2336.70	4629.30	15328.10	7.64	7.64	.0%
Templeton	2529.00	5011.00	15679.00	8.27	7.62	7.9%
Wakefield	2773.16	5432.45	17724.87	8.86	8.78	0.9%
W. Boylston	2476.37	4952.73	16509.10	8.25	8.25	.0%
Westfield	1992.20	3916.40	12896.00	6.41	6.41	.0%

[1] h-g/300
[2] i-h/1400
[3] 1-([2]/[1])

TABLE 5.13: Reduction in Electric Consumption as a Result of Increases in Marginal Prices

Marginal Electric Price Increase	Marginal Price Elasticity -0.5	-0.8	-1.1
10%	4.7%	7.3%	10.0%
20%	8.7%	13.6%	18.2%
30%	12.3%	18.9%	25.1%
40%	15.5%	23.6%	30.9%
50%	18.4%	27.7%	36.0%

TABLE 5.14: Potential Savings from Selected Appliance Efficiency Investments

Finance Cost 12.0%

1985 Customers 222411
1999 Customers 275862

Device	VS.	Cost (installed) Gross	Net [4]	Life	Annual Kwh Savings [3]	Cts/ Kwh [5]	Saturation [2] 1984	1999	Annual Total MWH Savings 1984/85	1999
Heat pump	Existing resistance	$3,500	$3,500	12	6154	9.18	7.0%	--	95808	95808
Heat pump	New resistance	--	$1,400	12	6154	3.67	--	7.6%		32837
Heat pump H20 heater	Average New 1980	$1,550	$1,200	13	4270	4.38	21.7%	28.2%	206063 *	332143
Add-on	Average New 1980	--	$1,100	13	3905	4.39	21.7%	28.2%	188468	303782 *
Refrigerator	Average New 1981	$900	$100	19	250	5.43	81.4%	100.9%	45196	69522
Freezer [1]	Average New 1981	$510	$40	19	75	7.26	34.4%	39.9%	5722	8231
Total									335193	538542

NOTES: [1] Assumes same Kwh savings available for frost-free as for manual

[2] Massachusetts saturations, NEPOOL model.

[3] Efficiency improvements are assumed to be:

61.5% for heat pump;

77.6% for water heater;

71.0% for water heater, add-on heat-pump;

29.2% for refrigerator;

18.2% for freezer.

Standard consumption is from MMWEC, including forecast efficiency target:

10000 Kwh for space heat;

5500 Kwh for hot water;

856 Kwh for refrigerator;

410 Kwh for freezer.

[4] Gross cost minus cost of less efficient device.

[5] For net cost.

* Excluded from Total

COMPUTATION OF MMWEC SEABROOK COMMITMENT NOMINAL ANNUAL COST ($thousand)

Case 1: MMWEC Assumptions

	Seabrook		
Firstyr	1988	Future Investments	15.0%
Share (% plant)	11.43%	Discount rate	11.0%
Total cost (B)	$5.50 billion	Finance Life	25

year	MMWEC Costs [1] Case 1	Case 2	Case 3	Case 4	Net capital costs Case 1	Capital additions [4]	O&M [2]	Indirect O&M	Insurance [3]	MMWEC Decommissioning [2]
1	126956	135832	171340	78384	48571	1827	6976		1892	2956
2	119816	126700	154237	86670	33145	1947	7429		2005	2956
3	120442	127193	154198	86457	33984	2207	8422		2126	3146
4	120611	127556	155340	86183	34427	2778	10600		2253	3718
5	120541	127535	155512	85972	34568	2957	11288		2389	3718
6	120439	127392	155208	85767	34671	3151	12020		2532	3718
7	119829	126584	153605	84998	34830	3405	12990		2684	3773
8	119715	126408	153181	84407	35307	3986	15197		2845	4145
9	120564	127558	155538	84492	36071	4887	18626		3015	4771
10	120750	127745	155726	84509	36240	5204	19837		3196	4771
11	120944	127938	155918	84524	36419	5543	21127		3388	4771
12	121150	128144	156124	84538	36611	5903	22499		3591	4771
13	121382	128377	156358	84566	36815	6287	23962		3807	4771
14	121382	128377	156358	84566	36815	6696	25520		4035	4771
15	121382	128377	156358	84566	36815	7131	27179		4278	4771
16	121382	128377	156358	84566	36815	7594	28945		4534	4771
17	121382	128377	156358	84566	36815	8088	30827		4806	4771
18	121382	128377	156358	84566	36815	8614	32831		5095	4771
19	121382	128377	156358	84566	36815	9173	34965		5400	4771
20	121382	128377	156358	84566	36815	9770	37237		5724	4771
21	121382	128377	156358	84566	36815	10405	39658		6068	4771
22	121382	128377	156358	84566	36815	11081	42235		6432	4771
23	121382	128377	156358	84566	36815	11801	44981		6818	4771
24	121382	128377	156358	84566	36815	12568	47904		7227	4771
25	121382	128377	156358	84566	36815	13385	51018		7660	4771

Notes:
1. From: MMWEC Work Papers, Vol. 32; includes debt, R&C, property taxes, transmission, and MMWEC A&G Costs held constant after 2000.
2. From MMWEC Work Papers, Vol. 32.
3. 13110*SHARE*(1.06^(yr - 1984))
4. From MMWEC Work Papers, Vol. 32.
5. Easterling + 3%

NET COSTS						TOTAL COSTS				
Net non-fuel costs	Capacity factor [5]	Non-fuel cents/ kWh	MMWEC fuel cents/ kWh	Net cents/ kWh	Levelized cents/kwh	Total non-fuel costs	Non-fuel cents/ kWh	Total cents/ kWh	Levelized cents/kwh	1983 Rate increase (vs. 6 ct. oil)
62222	59%	9.1	0.9	10.0	10.0	140607	20.6	21.4	21.4	105441
47483	62%	6.7	1.0	7.7	8.9	134154	18.9	20.0	20.7	
49885	64%	6.8	1.2	7.9	8.6	136342	18.5	19.7	20.4	
53777	65%	7.2	1.4	8.5	8.6	139960	18.7	20.1	20.3	
54920	65%	7.3	1.4	8.8	8.6	140893	18.8	20.2	20.3	
56093	65%	7.5	1.6	9.1	8.7	141860	19.0	20.6	20.3	
57683	65%	7.7	1.8	9.5	8.8	142681	19.1	20.8	20.4	
61480	65%	8.2	2.0	10.3	8.9	145887	19.5	21.5	20.5	
67370	65%	9.0	2.2	11.2	9.1	151863	20.3	22.5	20.6	
69249	65%	9.3	2.4	11.6	9.2	153759	20.5	22.9	20.8	
71248	65%	9.5	2.5	12.1	9.4	155773	20.8	23.4	20.9	
73376	65%	9.8	2.7	12.5	9.5	157915	21.1	23.8	21.0	
75643	65%	10.1	2.9	13.0	9.6	160209	21.4	24.3	21.2	
77837	65%	10.4	3.1	13.5	9.8	162404	21.7	24.8	21.3	
80173	65%	10.7	3.3	14.0	9.9	164740	22.0	25.3	21.4	
82660	65%	11.0	3.6	14.6	10.0	167226	22.3	25.9	21.5	
85307	65%	11.4	3.8	15.2	10.1	169874	22.7	26.5	21.6	
88125	65%	11.8	4.1	15.9	10.2	172691	23.1	27.1	21.7	
91125	65%	12.2	4.4	16.5	10.3	175691	23.5	27.8	21.8	
94318	65%	12.6	4.7	17.3	10.5	178884	23.9	28.6	21.9	
97716	65%	13.1	5.0	18.0	10.6	182283	24.4	29.3	22.0	
101335	65%	13.5	5.3	18.9	10.7	185901	24.8	30.2	22.1	
105186	65%	14.1	5.7	19.8	10.8	189752	25.4	31.1	22.2	
109286	65%	14.6	6.1	20.7	10.9	193852	25.9	32.0	22.3	
113650	65%	15.2	6.5	21.7	11.0	198217	26.5	33.0	22.4	

COMPUTATION OF MMWEC SEABROOK COMMITMENT NOMINAL ANNUAL COST ($thousand)

Case 2: Optimistic Cost Completion

	Seabrook		
Firstyr	1988	Future Investments	15.0%
Share (% plant)	11.43%	Discount rate	11.0%
Total cost (B)	$6.00 billion	Finance Life	25

year	MMWEC Costs [1] Case 1	Case 2	Case 3	Case 4	Net capital costs Case 1	Capital additions [4]	O&M [2]	Indirect O&M Insurance [3]	MMWEC Decommi-ssioning [6]
1	126956	135832	171340	78384	57448	4837	11509	1892	2956
2	119816	126700	154237	86670	40030	5195	12813	2005	2956
3	120442	127193	154198	86457	40736	5580	14233	2126	3146
4	120611	127556	155340	86183	41373	5993	15777	2253	3718
5	120541	127535	155512	85972	41563	6436	17455	2389	3718
6	120439	127392	155208	85767	41625	6912	19277	2532	3718
7	119829	126584	153605	84998	41586	7424	21255	2684	3773
8	119715	126408	153181	84407	42001	7973	23402	2845	4145
9	120564	127558	155538	84492	43066	8563	25729	3015	4771
10	120750	127745	155726	84509	43236	9197	28251	3196	4771
11	120944	127938	155918	84524	43414	9877	30984	3388	4771
12	121150	128144	156124	84538	43606	10608	33942	3591	4771
13	121382	128377	156358	84566	43811	11393	37144	3807	4771
14	121382	128377	156358	84566	43811	12237	40608	4035	4771
15	121382	128377	156358	84566	43811	13142	44354	4278	4771
16	121382	128377	156358	84566	43811	14115	48404	4534	4771
17	121382	128377	156358	84566	43811	15159	52780	4806	4771
18	121382	128377	156358	84566	43811	16281	57506	5095	4771
19	121382	128377	156358	84566	43811	17486	62610	5400	4771
20	121382	128377	156358	84566	43811	18780	68119	5724	4771
21	121382	128377	156358	84566	43811	20169	74064	6068	4771
22	121382	128377	156358	84566	43811	21662	80477	6432	4771
23	121382	128377	156358	84566	43811	23265	87393	6818	4771
24	121382	128377	156358	84566	43811	24986	94849	7227	4771
25	121382	128377	156358	84566	43811	26835	102885	7660	4771

Notes: 1. From: MMWEC Work Papers, Vol. 32; includes debt, R&C, property taxes, transmission, and MMWEC A&G Costs held constant after 2000.
2. See Tables 3.23-25, PLC testimony 84-152: SHARE*[45557+3186.5*(yr-1983)]*1.06^(yr-1984).
3. 13110*SHARE*(1.06^(yr - 1984))
4. 26.24*1150*share*1.054*(1.074^(yr - 1984)); see Table 3.26, DPU 84-152.
5. Easterling + 3%
6. From MMWEC Work Papers, Vol. 32.

NET COSTS						TOTAL COSTS				
Net non-fuel costs	Capacity factor [5]	Non-fuel cents/ kWh	MMWEC fuel cents/ kWh	Net cents/ kWh	Levelized cents/kwh	Total non-fuel costs	Non-fuel cents/ kWh	Total cents/ kWh	Levelized cents/kwh	1983 Rate increase (vs. 6 ct. oil)
78642	50%	13.6	0.9	14.5	14.5	157026	27.2	28.0	28.0	127307
63000	50%	10.9	1.0	11.9	13.3	149670	25.9	26.9	27.5	
65820	53%	10.9	1.2	12.0	12.9	152277	25.1	26.3	27.1	
69114	55%	10.9	1.4	12.3	12.8	155297	24.5	25.9	26.9	
71560	57%	10.8	1.4	12.3	12.7	157532	23.9	25.3	26.6	
74064	57%	11.2	1.6	12.8	12.7	159832	24.2	25.8	26.5	
76722	57%	11.6	1.8	13.4	12.8	161720	24.5	26.3	26.5	
80365	57%	12.2	2.0	14.2	12.9	164773	25.0	27.0	26.5	
85145	57%	12.9	2.2	15.1	13.1	169637	25.7	27.9	26.6	
88651	57%	13.4	2.4	15.8	13.2	173161	26.2	28.6	26.8	
92434	57%	14.0	2.5	16.5	13.4	176959	26.8	29.4	26.9	
96519	57%	14.6	2.7	17.3	13.6	181058	27.4	30.2	27.0	
100926	57%	15.3	2.9	18.2	13.7	185493	28.1	31.0	27.2	
105462	57%	16.0	3.1	19.1	13.9	190028	28.8	31.9	27.3	
110356	57%	16.7	3.3	20.1	14.1	194922	29.5	32.9	27.5	
115634	57%	17.5	3.6	21.1	14.3	200201	30.3	33.9	27.7	
121326	57%	18.4	3.8	22.2	14.5	205893	31.2	35.0	27.8	
127463	57%	19.3	4.1	23.4	14.6	212030	32.1	36.2	28.0	
134077	57%	20.3	4.4	24.7	14.8	218644	33.1	37.5	28.2	
141204	57%	21.4	4.7	26.1	15.0	225771	34.2	38.9	28.3	
148882	57%	22.6	5.0	27.6	15.2	233449	35.4	40.4	28.5	
157152	57%	23.8	5.3	29.2	15.3	241718	36.6	42.0	28.7	
166057	57%	25.2	5.7	30.9	15.5	250623	38.0	43.7	28.8	
175643	57%	26.6	6.1	32.7	15.7	260210	39.4	45.6	29.0	
185962	57%	28.2	6.5	34.7	15.8	270529	41.0	47.5	29.2	

COMPUTATION OF MMWEC SEABROOK COMMITMENT NOMINAL ANNUAL COST ($thousand)

Case 3: Higher Cost Completion

	Seabrook		
Firstyr	1988	Future Investments	15.0%
Share (% plant)	11.43%	Discount rate	11.0%
Total cost (B)	$8.00 billion	Finance Life	25

year	MMWEC Costs [1] Case 1	Case 2	Case 3	Case 4	Net capital costs Case 1	Capital additions [4]	O&M [2]	Indirect O&M Insurance [3]	MMWEC Decommi-ssioning [6]
1	126956	135832	171340	78384	92955	4837	11509	1892	2956
2	119816	126700	154237	86670	67567	5195	12813	2005	2956
3	120442	127193	154198	86457	67741	5580	14233	2126	3146
4	120611	127556	155340	86183	69156	5993	15777	2253	3718
5	120541	127535	155512	85972	69540	6436	17455	2389	3718
6	120439	127392	155208	85767	69440	6912	19277	2532	3718
7	119829	126584	153605	84998	68607	7424	21255	2684	3773
8	119715	126408	153181	84407	68774	7973	23402	2845	4145
9	120564	127558	155538	84492	71045	8563	25729	3015	4771
10	120750	127745	155726	84509	71217	9197	28251	3196	4771
11	120944	127938	155918	84524	71393	9877	30984	3388	4771
12	121150	128144	156124	84538	71585	10608	33942	3591	4771
13	121382	128377	156358	84566	71792	11393	37144	3807	4771
14	121382	128377	156358	84566	71792	12237	40608	4035	4771
15	121382	128377	156358	84566	71792	13142	44354	4278	4771
16	121382	128377	156358	84566	71792	14115	48404	4534	4771
17	121382	128377	156358	84566	71792	15159	52780	4806	4771
18	121382	128377	156358	84566	71792	16281	57506	5095	4771
19	121382	128377	156358	84566	71792	17486	62610	5400	4771
20	121382	128377	156358	84566	71792	18780	68119	5724	4771
21	121382	128377	156358	84566	71792	20169	74064	6068	4771
22	121382	128377	156358	84566	71792	21662	80477	6432	4771
23	121382	128377	156358	84566	71792	23265	87393	6818	4771
24	121382	128377	156358	84566	71792	24986	94849	7227	4771
25	121382	128377	156358	84566	71792	26835	102885	7660	4771

Notes: 1. From: MMWEC Work Papers, Vol. 32; includes debt, R&C, property taxes, transmission, and MMWEC A&G Costs held constant after 2000.
2. See Tables 3.23-25, PLC testimony 84-152: SHARE*[45557+3186.5*(yr-1983)]*1.06^(yr-1984).
3. 13110*SHARE*(1.06^(yr - 1984))
4. 26.24*1150*share*1.054*(1.074^(yr - 1984)); see Table 3.26, DPU 84-152.
5. Easterling + 3%
6. From MMWEC Work Papers, Vol. 32.

NET COSTS						TOTAL COSTS				
Net non-fuel costs	Capacity factor [5]	Non-fuel cents/ kWh	MMWEC fuel cents/ kWh	Net cents/ kWh	Levelized cents/kwh	Total non-fuel costs	Non-fuel cents/ kWh	Total cents/ kWh	Levelized cents/kwh	1983 Rate increase (vs. 6 ct. oil)
114149	50%	19.7	0.9	20.6	20.6	192534	33.3	34.2	34.2	162814
90537	50%	15.7	1.0	16.7	18.7	177207	30.7	31.7	33.0	
92825	53%	15.3	1.2	16.5	18.1	179283	29.6	30.8	32.3	
96897	55%	15.3	1.4	16.7	17.8	183080	28.9	30.3	31.9	
99537	57%	15.1	1.4	16.5	17.6	185509	28.1	29.5	31.5	
101880	57%	15.4	1.6	17.0	17.5	187647	28.4	30.0	31.3	
103743	57%	15.7	1.8	17.5	17.5	188741	28.6	30.4	31.2	
107138	57%	16.2	2.0	18.3	17.6	191546	29.0	31.1	31.2	
113124	57%	17.1	2.2	19.4	17.7	197616	29.9	32.2	31.3	
116632	57%	17.7	2.4	20.1	17.8	201142	30.5	32.9	31.4	
120414	57%	18.2	2.5	20.8	18.0	204938	31.1	33.6	31.5	
124498	57%	18.9	2.7	21.6	18.1	209037	31.7	34.4	31.6	
128907	57%	19.5	2.9	22.4	18.3	213474	32.4	35.3	31.8	
133443	57%	20.2	3.1	23.3	18.5	218009	33.0	36.2	31.9	
138337	57%	21.0	3.3	24.3	18.6	222903	33.8	37.1	32.1	
143615	57%	21.8	3.6	25.3	18.8	228182	34.6	38.1	32.2	
149308	57%	22.6	3.8	26.4	19.0	233874	35.4	39.3	32.4	
155444	57%	23.6	4.1	27.6	19.2	240011	36.4	40.5	32.5	
162058	57%	24.6	4.4	28.9	19.3	246625	37.4	41.7	32.7	
169186	57%	25.6	4.7	30.3	19.5	253752	38.5	43.1	32.9	
176864	57%	26.8	5.0	31.8	19.7	261430	39.6	44.6	33.0	
185133	57%	28.1	5.3	33.4	19.8	269699	40.9	46.2	33.2	
194038	57%	29.4	5.7	35.1	20.0	278604	42.2	47.9	33.3	
203625	57%	30.9	6.1	37.0	20.2	288191	43.7	49.8	33.5	
213943	57%	32.4	6.5	39.0	20.3	298510	45.2	51.8	33.7	

EOER-10 #43

THE COMMONWEALTH OF MASSACHUSETTS
BEFORE THE DEPARTMENT OF PUBLIC UTILITIES

RE: INVESTIGATION OF THE MMWEC FINANCING PLAN FOR SEABROOK UNIT 1	DOCKET No. 1627

ERRATA TO THE
TESTIMONY OF PAUL CHERNICK
ON BEHALF OF THE
EXECUTIVE OFFICE OF ENERGY RESOURCES

February 11, 1985

ERRATA TO THE

TESTIMONY OF PAUL CHERNICK

ON BEHALF OF THE EXECUTIVE OFFICE

OF ENERGY RESOURCES

Page 9	The semi-colon in the middle of the page, following the word "years", should be a comma.
Page 14	Footnote 9 should read:
	9. The low end of these ranges used MMWEC's assumed operating characteristics and the Newbrook cost estimate, both of which are very optimistic.
Page 43	The reference to "15 MW" should read "12 -14 MW".
Page 46	The reference to "15% lower" should read "12% lower", and the reference to "3.2 - 4.8 cents/kWh" should read "3.3 - 4.9 cents/kWh".
Page 49	The reference to "7 MW" should read "6 MW", and the reference to "150 MW" should read "118 MW".
Page 89	The reference to "72,600 MWH" should read "38,900 MWH".
Page 108	The bibliography should include cites to NEPOOL (1977a) and NEPOOL (1977b), which are cited in Footnote 14 on page 26. These cites would be:
	New England Power Pool (NEPOOL), "Agreement by NEPOOL Companies for Uniform Rating and Periodic Audit of Generating Capability," Revised 7/29/77.
	New England Power Pool (NEPOOL), "Instructions for Periodic Capability Audit Tests of NEPOOL Generating Units," Generating Capability Task Force (approved by NEPOOL Operations Committe), Revised 7/29/77.

The documents were provided in response to Request C-36.

Table 5.14	Table 5.14 has been revised, primarily to reflect the fact that MMWEC did not apply the reduction in average use implied by the forecast documentation, as explained in Supplementary Response C-101. The revised Table is attached.

TABLE 5.14 (Revised): Potential Savings from Selected Appliance Efficiency Investments

Finance Cost 12.0%

1985 Customers 222411
1999 Customers 275862

Device	VS.	Cost (installed) Gross	Net [4]	Life	Annual Kwh Savings [3]	Cts/ Kwh [5]	Saturation [2] 1984	1999	Annual Total MWH Savings 1984/85	1999
Heat pump	Existing resistance	$3,500	$3,500	12	6154	9.18	7.0%	--	95808	95808
Heat pump	New resistance	--	$1,400	12	6154	3.67	--	7.6%		32837
Heat pump H20 heater	Average New 1980	$1,550	$1,200	13	4270	4.38	21.7%	28.2%	206063 *	332143
Add-on	Average New 1980	--	$1,100	13	3905	4.39	21.7%	28.2%	188468	303782 *
Refrigerator	Average New 1981	$900	$100	19	280	4.85	81.4%	100.9%	50605	77843
Freezer [1]	Average New 1981	$510	$40	21	170	3.11	34.4%	39.9%	13008	18713
Total									347888	557344

NOTES: [1] Assumes same Kwh savings available for frost-free as for manual

[2] Massachusetts saturations, NEPOOL model.

[3] Efficiency improvements are assumed to be:

61.5% for heat pump;

77.6% for water heater;

71.0% for water heater, add-on heat-pump;

29.2% for refrigerator;

18.2% for freezer.

Standard consumption is from MMWEC, including forecast efficiency target:

10000 Kwh for space heat;

5500 Kwh for hot water;

958 Kwh for refrigerator;

933 Kwh for freezer.

[4] Gross cost minus cost of less efficient device.

[5] For net cost.

* Excluded from Total