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**FACTORS AFFECTING THE POTENTIAL OF
DIRECT LOAD CONTROL
FOR
NON-GENERATING UTILITIES**

FINAL REPORT

MANUSCRIPT COMPLETED: JANUARY 1979

DATE PUBLISHED: APRIL 1979

Volume II

prepared for:

**ELECTRIC ENERGY SYSTEMS
DEPARTMENT OF ENERGY**

CONTRACT NO. EC-76-C01-2099

Gilbert/Commonwealth

ENGINEERS/CONSULTANTS Reading, PA/Jackson, MI

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CASE STUDIES

INTRODUCTION

The attendant Report has discussed various control systems and has proposed a methodology for an assessment of the feasibility of direct load control in the environment of a non-generating electric utility. In order to provide a basis for a practical application of the concepts previously introduced, four test cases, each representative of a unique circumstance, have been developed.

The Case Studies which follow are demonstrative of the application of load control evaluation techniques under conditions varying both in the nature of the service area and the load characteristics of the customers served. Test utilities have been chosen to represent the following sequence of operating criteria:

<u>CASE NUMBER</u>	<u>NATURE OF SERVICE AREA</u>	<u>SEASON OF PEAK DEMAND</u>
1	Urban	Winter
2	Rural	Winter
3	Urban	Summer
4	Rural	Summer

The illustrative cases also exhibit varying types of ownership and, as a correlative, different forms of financing. As an investor owned company, the Case #1 utility is capitalized through privately placed debt and equity. Both rural cases (#2 and #4) relate to member-owned cooperatives eligible for REA type financing, and, finally, the summer peaking-urban Case #3 is a public authority resorting to municipal bonds to cover major expenditures.

In each case, five generic types of load control systems were investigated:

- I. Radio
- II. Hybrid - Radio/Power Line Carrier
- III. Low Frequency Power Line Carrier - Rhythm Keying
- IV. Low Frequency Power Line Carrier - Multibit Coding
- V. High Frequency Power Line Carrier - One Way

Telephonic and Direct Wire (Local Logic) systems were not treated in this analysis because of the absence of any standardized cost or equipment ownership criterion and the 'breadboard' characteristics of direct wire systems (i.e., widely different component parts). Also the uncertainties in estimating the amount of controllable loads were prohibitive.

Further, the attributes of the High Frequency system were investigated only insofar as they relate to direct load control. Because of the nature of the utilities* investigated and the subjective nature of decisions affecting the adoption of two way control systems, the inclusion of any investigation related to the reverse communication features of these systems was considered to be potentially misleading on the generalized basis inherent in these case studies. Consequently, all High Frequency System costs are developed only as they pertain to direct load control, and, for all generic systems, benefits are limited to those resulting therefrom.

However, the ability of these systems to accomplish two way communication is well established, and the potential application of the ancillary functions made possible thereby is a factor to be carefully weighed in any evaluation preparatory to actual decision as between load control systems.

* In some cases, for example, customers presently read their own meters.

Vendor prices quoted reflect 1975-1976 levels. Design modifications, competitive biddings, manufacturing cost changes and regulatory environment will, of course, influence future prices. Furthermore, the price quotes from some of the vendors were given on a basis of "when available for full production." These latter quotes in most cases reflect a 1976-1977 time frame. Vendor prices and installation changes were combined to develop installed costs.

One important limitation imposed on the analysis is that it considers only one type of communication and control system at a time. No blending of systems to possibly match system irregularities more optimally was attempted.

For each communication and control system, the following general assumptions were made:

<u>Radio</u>	15 mile coverage, extended only when actual experience indicated otherwise
<u>Hybrid</u>	Joint use of existing base station facilities for 2-way voice and load control. Also assumed: $\frac{\# \text{Controlled Customers}}{\# \text{Transformers}} = \frac{\# \text{Total Customers}}{\# \text{Transformers}}$
<u>Low Frequency Power Line Carrier</u>	Injection equipment costs based on a fully protected feeder bay at 34.4 Kv and above with fuse disconnects below 34.4 Kv. An injection at transmission voltage assumed only when multiple bulk supply points were fed from a common system.
<u>High Frequency Power Line Carrier</u>	Medium voltage injection only. Separate bus and telephone lines for each section injection point. Control center equipment was costed for functional load control only. Bulk supply point telemetry is independent of any remote meter reading facilities.

A comparison of individual results for the several case studies should not be construed as a basis for any candid statement of the "best" system for a non-generating utility. As the findings of this study point out, the costs and applications are far too sensitive to the electrical system, and the configuration and extent of end-use loads, to make such a gross determination on the basis of collective results.

All cases were reviewed with the management and technical staffs of the test utilities and reflect specific physical system attributes to the fullest extent feasible for economic analysis. In consideration of the fact that individual interest may lie with a particular case study, each case has been structured as a complete entity in itself. As a consequence, a continuous reading through all case studies will necessarily encounter an inevitable degree of redundancy.

CASE #1WINTER PEAKING - URBAN SYSTEM

Case #1 examines the potential for load control from the perspective of a winter peaking utility located in northern New England. The utility covers a compact and hilly area approximately 16 miles by 12 miles consisting of a predominately urban type residential, commercial and industrial community. It is noted that this is an established community and is not subject to rapid changes or development often encountered in newer developing area. The electrical network is similarly well established and comprises a 34.5 kV network feeding a comparatively large number of small distribution transformer substations. The 34.5 kV system is fed from a major bulk supply substation in addition to alternative feeds at one other location. Except for abnormal conditions, the 34.5 kV system is run unsectioned. Because of its location, the Case #1 Company experiences various degrees of winter weather over approximately eight months of the year. Annual peak demands occur routinely in the evening hours between 5 p.m. and 7 p.m. and during the months of December, January or February. Currently, peak capacity requirements are in excess of 66 MW.

As with most non-generating utilities, the costs of purchased power represent the single largest component of the Company's operating costs currently representing approximately 75% of total operation and maintenance expense. Logically, the thrust of any load control strategy devised should be directed toward minimizing the monthly coincident peak demands which occasion the capacity charge component of the bill for purchased power.

A survey of potentially controllable loads indicated that 5,601, or approximately 27% of the Company's total residential customers have electrically operated water heaters. Since it has been demonstrated through many years of experience with time switches that water heater controls may be successfully implemented with a minimum of customer inconvenience, the methodology previously set forth in this report will be employed to evaluate relative costs and benefits under a control strategy formulated to avert water heater usage during periods otherwise establishing system peak demands.

Load Control Strategy

The load control strategy was derived by first examining the peak day load profile of the utility under study. The load curve shown in Exhibit 1-A illustrates the winter peaking urban utility's peak day load profile with the familiar peak (60 MW) in the early evening hours and subsequent decay toward midnight. It is important that this curve is accurate since the strategy is partially dependent upon the ability of the monitored demand of sampling points to "track" the forecasted demand.

With the peak load identified, the next step was to evaluate the controllable load. In this case only water heaters were controlled. Therefore, the diversified demand data for water heaters (Exhibit 1-B) was obtained from a neighboring utility's test data. Total controllable load at the delivery point is the product of the number of water heaters (5,601), their diversified demand at the time of the system peak (0.8 KW via Exhibit 1-B), the loss factor (1.0989) and the estimated load control switch success rate (0.98). The result was a total controllable load of 4,825 KW. Subtracting this from the system peak demand of 59,900 KW, the control target became 55,075 KW.

The control strategy consisted of controlling 5,601 water heaters in such a manner as to minimize customer inconvenience, but still keep system load below the control target. The control had to be variable and have a fast response time. To achieve these objectives, the total number of water heaters was divided into ten equal groups of 560 water heaters. Each group was controlled as a separate unit. Exhibits 1-C and 1-D illustrate the control sequence selected. These exhibits show that at 4:15 PM the load growth was such that three water heater groups had to be inhibited to preserve the control target demand. The group demand at the time of inhibit, as derived from Exhibit 1-B, determined the amount of load shed and resultant demand. To illustrate: at 4:15 each water heater had a diversified demand of 0.66 KW. With 560 heaters in each group, group demand became 398 KW (adjusting for loss factor and switch success rate). Since there are 3 groups inhibited, the total load shed at 4:15 is 1,194 KW, reducing system demand to 53,881 KW. Exhibit 1-D, illustrates this load shed as the small vertical dashed line at 4:15. Note the number 3 at 4:15 indicating the number of groups inhibited. By 4:30, 5 more groups were inhibited bringing the total to 8. At 4:45 all 10 groups have been inhibited and remain so until 6:00 PM. At this time the system load has dropped sufficiently to allow one control group to be restored without raising the resultant demand above the control target. As Exhibit 1-C illustrates, by 6:00 the first group restored (Group #1) had been off for 1.75 hours (4:15 to 6:00). From the restore demand curves ("payback curves") shown in Section III of this report, the restore demand for this group is seen to be 3.18 times the original diversified demand. As Exhibit 1-C illustrates, the total restore demand at this time is 1,265 KW. The effect of this restore demand can be seen as the vertical dashed line in Exhibit 1-D. As indicated in Exhibit 1-C, under the column entitled "Restorable Load" the margin between the actual

load and the control target at 6:00 PM is 2,200 KW. Therefore, only one group can be restored at this time. Each groups' restored demand follows a separate payback curve down to the point of normal diversified demand. Exhibit 1-C shows that the payback period extends for up to 6 hours after the point of restore.

Control groups were restored every 15 minutes except in two instances when the system load did not allow for any restoration. By 8:45 all ten water heater groups were restored. In this manner the control target was never exceeded. Exhibit 1-E illustrates the overall effect on the system peak day load profile, and the "cause", i.e., how the water heater load changes as a result of load control.

Case 1 illustrates that by controlling 5,601 water heaters in a winter peaking urban utility of 60 MW, the peak can be reduced by 8%. The average off time was 2 hours and 45 minutes with no group off longer than 4 hours.

Development of Control System Costs

Control costs are developed for each of five generic types of control systems. In each case, costs are established on the basis of a 100% acceptance rate; i.e., agreement by all 5,601 water heater customers to accept such controls.

1. The Cost of Acquiring and Installing Control Apparatus

As indicated in Exhibit VIII-1 shown in Section VIII, installed system costs include both direct and indirect charges representing actual costs due vendors or other costs incurred by the utility in connection with the acquisition or installation of control facilities. Details supporting the development of overall installed costs for each generic type of control system are included in Exhibit 1-F. Each estimate used as a basis the actual conditions prevailing at the location under study both in terms of system configuration and physical requirements. Pertinent features of alternative types of installation in the specific operating environment investigated are as follows:

- a. Radio - The utility's experience with a presently installed two-way voice VHF radio system indicates that adequate coverage of the entire distribution area may be achieved with a single transmitter. Costs for a Radio Control System, detailed in Exhibit 1-F-I are predicated on the joint use of such common facilities as transmitter housing, power supply and antenna tower representing a significant cost saving. Total estimated costs for a Radio Control System are summarized below.

Radio Control System

Direct costs including spares	\$414,830
Indirect costs including contingencies	<u>99,805</u>
Total Installed Cost	<u>\$514,635</u>

- b. Hybrid: Radio and Power Line Carrier - The radio portion of this system carries with it the same cost savings recognized above. In addition, shared use of the VHF transmitter appears feasible. As developed in Exhibit 1-F-II and summarized below, system costs clearly benefit from the urban character of the study area as reflected in the favorable ratio of controlled customers per transformer.

Hybrid Control System

Direct costs including spares	\$466,515
Indirect costs including contingencies	<u>158,355</u>
Total Installed Cost	<u>\$624,870</u>

- c. Low Frequency Power Line Carrier - As the system now exists, the application of a low frequency power line carrier is encouraged in that the system may be covered effectively by

the use of a single 34.5 KV injection point. It must be recognized that although single point injection represents the most economic present application, it is somewhat vulnerable to system changes although such changes as currently foreseen would appear to present little or no obstacle to successful operation of the control system as postulated.

The LF Power Line Carrier case is developed in both its simpler rhythm version and as a more complex multibit coded system. With the number of potentially controllable loads available the multibit version would appear to have little justification other than the additional versatility offered with respect to future control extensions. Costs associated with the respective Power Line Carrier scenarios are detailed in Exhibits 1-F-III and 1-F-IV and are summarized below.

	<u>LF POWER LINE CARRIER</u>	
	<u>Rhythm</u>	<u>Multibit</u>
Direct costs including spares	\$413,515	\$535,032
Indirect costs including contingencies	120,284	122,768
Total Installed Cost	<u>\$533,799</u>	<u>\$657,800</u>

- d. High Frequency Power Line Carrier - The somewhat limited range of the high frequency system suggests a conservative approach in the application of sector injection units for an area where the total number of controlled customers is a relatively small proportion of the total system (approximately 1 in 4). It is assumed that the controlled customer locations were substantially evenly distributed throughout the system and would thus dictate a relatively low loading factor on line type injection units. Off-setting this consideration was the relatively compact area and population density and an ultimate loading of approximately 60% of

the units' total capacity is assumed. Costs for equivalent substation units, would be the same order of magnitude with perhaps somewhat less assurance of total coverage.

To be comparable with the remaining studies, connections of the injection units to the control center is by means of individual based telephone lines although, as noted before, shared use of these lines by several injection units is probably more realistic.

Costs for the high frequency system are detailed in Exhibit 1-F-V and summarized below. It should be noted that although this system lends itself to two way communication and the ancillary functions associated therewith, only the single function of load control is treated herein.

High Frequency Power Line Carrier (One Way)

Direct costs including spares	\$ 799,022
Indirect costs including contingencies	165,410
Total Installed Cost	<u>\$ 964,432</u>

2. Operation and Maintenance Expense

Because of the relatively few points under control, it is not envisioned that any Company personnel need be exclusively dedicated to the operation of any of the control systems. By their nature, operation costs would consist primarily of charges for leased telephone lines or those associated with a microwave channel as applicable for the respective systems. On the other hand, anticipated maintenance costs consist primarily of personnel charges and consumable spares. Average annual O&M Expense estimates for each generic control system type are developed

in Exhibit 1-G and are summarized as follows:

<u>Control System</u>	<u>Estimated Average Annual Operation & Maintenance Expense</u>
I. Radio	\$14,398
II. Hybrid	15,354
III. LF Power Line Carrier - Rhythm	19,461
IV. LF Power Line Carrier - Multibit	23,131
V. HF Power Line Carrier	26,638

Development of Estimated Capacity Cost Savings

Since, by definition, each of the utilities considered in this analysis is non-generating, that is, dependent upon external sources for power supply, it is evident that the overwhelming benefit of load control will be reflected in reduced capacity charges for purchased power. Since, under the control strategy formulated, overall energy consumption will remain relatively unaffected by water heater control, no consideration of energy cost differentials is appropriate.

Load studies undertaken to establish diversified water heater demands during system peak hours indicate .8 KW per water heater in the winter months and .6 KW in summer periods to be a conservative estimate. These seasonal levels are adopted for purposes of this analysis.

In order to extrapolate control point demands to the point of wholesale delivery to the system, distribution losses must be recognized. For the subject utility, system losses under peak conditions represent approximately 9% of delivered kilowatts. Finally, it must be anticipated that some portion of water heater controls may not be operational at any given time. In recognition of this

factor, a 2% failure rate is incorporated in the development of total potentially controllable water heating loads. This determination may then be expressed as:

$$C = \frac{ND(1-F)}{1-L}$$

Where: C = Controlled Water Heater Load
 N = Number of Controlled Water Heaters
 D = Diversified Demand per Water Heater
 F = Failure Rate
 L = System Losses

Substituting values as indicated above, potentially controllable water heater demands during winter months is established as:

$$CW = \frac{(5,601)(.8KW)(1-.02)}{(1-.09)} = \underline{\underline{4,825 \text{ KW}}}$$

All factors remain the same for summer months except the diversified demand:

$$C_s = \frac{(5,601)(.6KW)(1-.02)}{(1-.09)} = \underline{\underline{3,619 \text{ KW}}}$$

Since the wholesale rate under which the utility purchases power provides for capacity charges at a fixed \$4.10 per KVA, it might be assumed that total annual savings would be the product of the capacity charge and the appropriate demands developed above after adjustment for power factor. However, several additional conditions must be recognized:

1. The purchased power rate imposes an 80% ratchet based on the peak demand over the preceeding eleven months.
2. Some degree of water heater control is presently effected through time switches.

These factors are considered in the detailed calculation of capacity cost savings developed in Exhibit 1-H which serves as the basis for water heater control benefits evaluated in the analysis which follows.

Evaluation of Water Heater Control Costs and Benefits

The methodology proposed for cost/benefit analysis is predicated on a consideration of relative annual or annual equivalent costs and/or benefits as levelized. A further basic consideration of the proposed methodology is that it takes its perspective from the viewpoint of the ultimate consumer's revenue requirements.

Accordingly, control system costs are translated into annual fixed charges representing levelized costs to the ratepayer in the form of capital recovery, return on investment, property taxes and in the instant case, income taxes. Although each of these factors may and generally do vary over each year of the control system's service life, engineering economy studies frequently express such fixed charges through application of a levelized fixed charge rate recognizing each of the factors indicated above and other elements of fixed cost as appropriate.

Fixed Charge Rate

The utility serving as the model for the winter peaking urban system is investor owned. Consequently, the cost of money component of the fixed charge rate consists of both equity and debt in the following proportions consistent with the Company's actual capital structure:

Long Term Debt	52%
Preferred Stock	10%
Common Equity	38%

Since the Company itself engaged in no new financing relevant to the time frame considered in this analysis, we have adopted average cost of money levels as reflected in Moody's Public Utilities for the period ended 1974. Average

yields for each class of capital are indicated as follows:

Medium Grade Bonds	9.65%
Preferred Stock	11.20
Common Stock	11.73

Weighting the Company's capital structure with the above yield levels results in a composite cost of money of 10.60%:

Class	<u>% of Total</u>	<u>Yield</u>	<u>Weighted</u>
Long Term Debt	52%	9.65%	5.02%
Preferred Stock	10%	11.20	1.12
Common Equity	38%	11.73	4.46
Composite Cost of Money			<u>10.60%</u>

Depreciation in the context of a fixed charge rate is established as the sinking fund charge indicated at an interest (discount) rate equal to the cost of money over the estimated service life of the investment. This may be expressed by the following formula:

$$D = \frac{(1-s)i}{(1+i)^n - 1}$$

Where: i = interest (discount) rate
 n = service life
 S = salvage value

Then, for a discount rate equal to the cost of money (10.60%) from above, and service life estimated at 15 years and zero salvage:

$$D = \frac{.1060}{(1.1060)^{15} - 1} = \frac{.1060}{3.5324} = .03 = \underline{\underline{3\%}}$$

The cost of money and sinking fund depreciation together constitute the capital recovery factor.

Based upon an analysis of actual Company tax levels, property taxes are estimated at a fixed annual level of 2.25% of investment.

Finally, since the subject utility is investor owned, it is subject to both state and federal income taxes before return. Since the calculation of the income tax component is fairly complex, the consultant has developed a computer program to develop annual fixed charges and a levelized fix charge rate. However, we have adapted the income tax calculation to a manual calculation in Exhibit 1-J for ready reference. It should be noted that in this illustration, Accumulated Deferred Income Taxes resulting from normalization of the effect of accelerated tax depreciation is treated as a reduction to Rate Base and consequently annual equivalent displaced earnings represent a credit to the Fixed Charge Rate.

In summary, the Fixed Charge Rate developed for application in Case #1 is then:

Case #1 Fixed Charge Rate

Cost of Money	10.60%
Depreciation	3.00
Property Taxes	2.25
Income Taxes	2.12
Displaced Earnings	(1.78)
Fixed Charge Rate	<u>16.19%</u>

Development of Levelized Annual Fixed Charges

Levelized annual fixed charges for each generic type of control system are developed as the product of individual Installed Cost estimates and the Fixed Charge Rate as developed above:

	GENERIC TYPE				
	I (Radio)	II (Hybrid)	III (LF-Rhythm)	IV (LF-Multibit)	V (HF-One Way)
Installed Cost	\$514,635	\$624,870	\$533,799	\$657,800	\$ 964,432
Fixed Charge Rate	16.19%	16.19%	16.19%	16.19%	16.19%
Levelized Fixed Charges	\$ 83,319	\$101,166	\$ 86,422	\$106,498	\$ 156,142

It should be noted that for this illustrative case, we have assumed a 15 year life and zero salvage value for each generic type. Any variation in either factor would obviously result in a different Fixed Charge Rate. The purpose of the methodology proposed is, in fact, to provide a valid basis for comparison when such differences exist as between generic types.

Development of Levelized Annual O&M Expense

Current (1975) levels of operation and maintenance expense estimates have been developed above for each generic type control system. It is likely, however, that, because of wage and other price adjustments, the level of annual O&M expense will escalate over the life cycle assumed for each control system. To account for this probability, each expense stream, as developed in Exhibit 1-K, includes escalation at an estimated level of 7% per annum through 1989, the fifteenth year of operation.

Under the proposed Benefit/Cost methodology, O&M expense is developed as the annual equivalent of the present worth of alternative expense streams. Again, since in the instant case the same service life (15 years) is assumed for each system, the necessity for this treatment is not as apparent. However, for illustrative purposes, the procedure has been carried out in Exhibit 1-K. The Present Worth Factor for each year as applied to yearly expense in order to develop present worth is the result of the following formula:

$$PWF_n = \frac{1}{(1+i)^n}$$

Where:

PWF_n = Present Worth Factor for Year n
 i = Discount Rate (In this Case 10.60%)
 n = year

Then:

$$PW = \sum_{n=1}^{15} \frac{E_n}{(1+i)^n} \quad \text{where } E_n = \text{yearly expense}$$

Total Present Worth for each O&M Expense stream is further shown in Exhibit 1-K. In order to express the respective amounts in terms of annual equivalents, an annuity factor is applied. The annuity factor results from the following formula:

$$AF = \frac{i (1+i)^n}{(1+i)^n - 1} = \underline{\underline{.136008}}, \text{ where } i = .1060 \text{ and } n = 15$$

On an annual equivalent basis, the O&M Expense component for each generic system is then:

	GENERIC TYPE				
	I	II	III	IV	V
Present Worth of Annual Expense	\$156,482	\$166,874	\$211,511	\$251,396	\$289,515
Annuity Factor	.136008	.136008	.136008	.136008	.136008
Annual Equivalent	<u>\$ 21,283</u>	<u>\$ 22,696</u>	<u>\$ 28,767</u>	<u>\$ 34,192</u>	<u>\$ 39,376</u>

Development of Levelized Capacity Cost Savings

For purposes of this analysis, load control system benefits are equated to savings in the capacity cost component of purchased power. The determination of current savings levels has been previously discussed and is detailed in Exhibit 1-H. As with other operating expenses, it is reasonable to assume that purchased power expense; and hence, capacity cost levels would continue to escalate in the future.

Recognizing this factor and applying the same technique previously described for O&M Expenses, the annual equivalent of the present worth of future capacity cost savings is developed as shown in Exhibit 1-L. Levelized annual capacity cost savings are calculated at \$285,260.

Summary of Costs and Benefits and Development of
Benefit/Cost Ratio and Payback Periods

Exhibit 1-M summarizes levelized annual costs and capacity cost savings for each load control system type analyzed.

The Benefit/Cost Ratio is favorable in each instance as further demonstrated in Exhibit 1-M and summarized below:

	GENERIC TYPE				
	<u>I</u>	<u>II</u>	<u>III</u>	<u>IV</u>	<u>V</u>
Benefit/Cost Ratio	<u>2.73</u>	<u>2.30</u>	<u>2.48</u>	<u>2.03</u>	<u>1.46</u>

As a further measure of project viability, the Payback Period, defined as the period necessary to recoup project costs through accumulated net savings, is developed for each system analyzed in Exhibit 1-N. Before and after Tax Payback Periods are summarized in Exhibit 1-M. It should be noted that for the High Frequency system, the payback period after taxes is shorter than that before taxes due to the significant tax depreciation and investment tax credit effects.

Sensitivity Analyses

The Benefit/Cost Ratios developed above are predicated, among other things, upon

1. 100% Acceptance Rate by Water Heater Customers
2. Escalation of future Capacity Cost Savings @ 7% p a

Obviously, actual circumstances could depart from those assumptions underlying this analysis.

In order to measure the impact of variations in either of these analysis components, we have prepared Exhibit 1-P in order to demonstrate levelized costs and benefits at acceptance rates varying from 0 to 100%. For this purpose, Load Control System costs were separated between fixed (central facilities, etc.) and variable (receivers, unit installation, etc.) components with the fixed portion applying even at 0% acceptance and variable costs incrementing with additional

connections. It should be noted that this graph was prepared on the basis of specific data for the case under analysis and should not be construed as being a general representation.

Exhibit 1-P also depicts capacity cost savings at various acceptance levels without escalation. It may be seen that even on this basis, favorable Benefit/Cost ratios would result in all cases with acceptance rates in excess of approximately 42%.

Customer Incentives

On a break-even basis, monthly customer incentive could be offered at a maximum level represented by the following:

$$CI = \frac{.0833 (B_1 - C_1)}{N}$$

Where: CI = Customer Incentive
 B₁ = Annual Equivalent Benefit for Generic Type 1
 C₁ = Annual Equivalent Cost for Generic Type 1
 N = Number of Water Heater Customers

From data developed above, maximum monthly customer incentive for the radio control system at the 100% acceptance rate would then be:

$$CI = \frac{.0833(285,260-103,495)}{5,601} = \frac{15,151}{5,601} = \underline{\underline{\$2.70 \text{ per month}}}$$

EXHIBIT 1A
CASE STUDY 1
WINTER PEAKING URBAN UTILITY
SYSTEM PEAK DAY LOAD PROFILE

EXHIBIT 1B
CASE STUDY 1
WINTER PEAKING URBAN UTILITY
TYPICAL WINTER LOAD PROFILE - WATER HEATERS

EXHIBIT 1-CWINTER PEAKING URBAN UTILITY - CONTROL SEQUENCE AT PEAK DAY

GIVEN: System Peak: 59,900 KW
 Max. Controllable Load: 4,825 KW
 Control Target: 55,075 KW
 Group Size: 560 Water Heaters

INHIBIT SEQUENCE

TIME OF INHIBIT	MIN. DEMAND REDUCTION NEC. IN NEXT 15 MIN.	GROUP DEMAND AT TIME OF INHIBIT	TOTAL NO. GROUPS INHIBITED	TOTAL LOAD SHED	RESULTANT DEMAND AT THIS TIME
4:15	1,190 KW	$560 \times 1.0989 \times .98 \times .66 = 398 \text{ KW}$	3	1,194 KW	53,881
4:30	3,000 KW	$560 \times 1.0989 \times .98 \times .68 = 410 \text{ KW}$	8	3,280 KW	52,900
4:45	4,200 KW	$560 \times 1.0989 \times .98 \times .70 = 422 \text{ KW}$	10	4,220 KW	52,800

RESTORE SEQUENCE

TIME OF RESTORE	RESTORABLE LOAD	GROUP DEMAND AT TIME OF RESTORE	GROUP OFF TIME	RESULTANT SYSTEM LOAD
6:00	2,200 KW	$560 \times 1.0989 \times .98 \times .66 \times 3.18 = 1,265 \text{ KW}$	1:45	54,200
6:15	2,100 KW	$560 \times 1.0989 \times .98 \times .66 \times 3.25 = 1,293 \text{ KW}$	2:00	54,200
6:30	2,200 KW	$560 \times 1.0989 \times .98 \times .66 \times 3.4 = 1,353 \text{ KW}$	2:15	54,200
6:45	2,000 KW	$560 \times 1.0989 \times .98 \times .68 \times 3.4 = 1,394 \text{ KW}$	2:15	54,400
7:00	1,440 KW	$560 \times 1.0989 \times .98 \times .68 \times 3.5 = 1,435 \text{ KW}$	2:30	55,000
7:15	N O T E N O U G H R E S T O R A B L E L O A D			
7:30	2,200 KW	$560 \times 1.0989 \times .98 \times .68 \times 3.75 = 1,537 \text{ KW}$	3:00	54,300
7:45	2,000 KW	$560 \times 1.0989 \times .98 \times .68 \times 3.85 = 1,578 \text{ KW}$	3:15	54,200
8:00	2,000 KW	$560 \times 1.0989 \times .98 \times .68 \times 3.9 = 1,599 \text{ KW}$	3:30	54,700
8:15	1,750 KW	$560 \times 1.0989 \times .98 \times .68 \times 3.9 = 1,646 \text{ KW}$	3:30	
8:30	N O T E N O U G H R E S T O R A B L E L O A D			
8:45	2,700 KW	$560 \times 1.0989 \times .98 \times .70 \times 4.1 = 1,730 \text{ KW}$	4:00

EXHIBIT 1D
LOAD CONTROL SIMULATION
WINTER PEAKING URBAN UTILITY
WATER HEATER CONTROL

EXHIBIT 1E
CASE STUDY 1
WINTER PEAKING URBAN
WATER HEATER CONTROL - EFFECT ON LOAD PROFILE

EXHIBIT 1-F-I

DOE LOAD CONTROL STUDY - NON GENERATING UTILITIESCase #1 - Winter Peaking Urban UtilityDEVELOPMENT OF INSTALLED COSTS - VARIOUS GENERIC SYSTEMSSystem I - Radio

	Amount Paid to Vendors	All Other Costs to the Utility	Total Cost
<u>DIRECT COSTS</u>			
5601 receivers @ \$70	\$392,070		
1 transmitter and antenna @ \$7,000	7,000		
1 antenna tower - joint use	-		
1 transmitter land line-joint use	-		
1 bulk supply point metering	2,500		
1 x 2 circuit leased line (10 circuit miles) @ \$60/circuit mile		\$ 120	
1 control center	4,000		
	\$405,570	\$ 120	\$405,690
Spares - 1 year operation			
112 - (2%) of receivers	\$ 7,840		
1 lot transmitter spares	700		
1 lot telemetering and control	600		
Total spares	\$ 9,140		\$ 9,140
<u>INDIRECT COSTS</u>			
Installation of 5601 receivers @ \$15		\$ 84,015	
Installation of transmitter 50 MH @ \$18		900	
Installation of control and telemetering 40 MH @ \$18		1,152	
Initial test 64 MH @ \$18		13,018	
Contingency 15%		\$ 99,805	\$ 99,805
Total			<u>\$514,635</u>

Average Cost/Customer - 91.88

EXHIBIT 1-F-II

DOE LOAD CONTROL STUDY - NON GENERATING UTILITIESCase #1 - Winter Peaking Urban UtilityDEVELOPMENT OF INSTALLED COSTS - VARIOUS GENERIC SYSTEMSSystem II - Hybrid: Radio and Power Line Carrier

	Amount Paid to Vendors	All Other Costs to the Utility	Total Cost
<u>DIRECT COSTS</u>			
5601 end-use receivers @ \$45	\$252,045		
1807 * VHF receivers @ \$110	198,770		
1 transmitter complete-joint use	-		
1 master controller @ \$6,000	6,000		
1 bulk supply metering point	2,500		
1 x 2 circuit leased lines (10 circuit miles) @ \$60/circuit mile		\$ 120	
	<u>\$459,315</u>	<u>\$ 120</u>	\$459,435
Spares - 1 year operation			
56 - (1%) of end-use receivers	\$ 2,520		
36 - (2%) of VHF receivers	3,960		
1 lot telemetering and control	600		
	<u>\$ 7,080</u>		\$ 7,080
<u>INDIRECT COSTS</u>			
Installation of 5601 end-use receivers @ \$15		\$ 84,015	
Installation of 1807 BHF receivers @ 1.5 MH		48,789	
Installation of control and telemetering @ 40 MH		720	
Initial test 1,548 x .15 = 232		4,176	
Contingency 15%		20,655	
		<u>\$158,355</u>	<u>\$158,355</u>
Total			<u>\$624,870</u>
Average Cost/Customer \$111.56			

* Assuming 3.1 controlled customer/transformer

EXHIBIT 1-F-III

DOE LOAD CONTROL STUDY - NON GENERATING UTILITIESCase #1 - Winter Peaking Urban UtilityDEVELOPMENT OF INSTALLED COSTS - VARIOUS GENERIC SYSTEMSSystem III - LF Power Line Carrier, Rhythm Keying

	<u>Amount Paid to Vendors</u>	<u>All Other Costs to the Utility</u>	<u>Total Cost</u>
<u>DIRECT COSTS</u>			
5601 receivers @ \$55	\$308,055		
1 - 34.5 KV injection equipment			
100 KVA audio	50,000		
1 - 34.5 KV substation switchgear bay		\$ 30,000	
1 bulk supply point metering @ \$3,000	2,500		
(1 x 1) + (1 x 2) circuit leased line			
(15 circuit miles) at \$60/circuit mile		180	
Control Center	7,000		
	<u>\$367,555</u>	<u>\$ 30,180</u>	<u>\$397,735</u>
Spares - 1 year operation			
56 - (1%) of receivers	\$ 3,080		
1 lot injection equipment spares	12,000		
1 lot telemetering and control	700		
Total spares	<u>\$ 15,780</u>		<u>\$ 15,780</u>
<u>INDIRECT COSTS</u>			
Installation of 5601 receivers @ \$15		\$ 84,015	
Installation of 34.5 KV injection \$15,000			
+ 100 MH @ \$18		16,800	
Installation of control and telemetering			
60 MH @ \$18		1,080	
Initial Tests - 150 MH @ \$18		2,700	
Contingency 15%		15,689	
		<u>\$120,284</u>	<u>\$120,284</u>
Total			<u><u>\$533,799</u></u>
Average Cost/Customer - \$95.30			

EXHIBIT 1-F-IV

DOE LOAD CONTROL STUDY - NON GENERATING UTILITIESCase #1 - Winter Peaking Urban UtilityDEVELOPMENT OF INSTALLED COSTS - VARIOUS GENERIC SYSTEMSSystem IV - LF Power Line Carrier, Multibit Code

	<u>Amount Paid to Vendors</u>	<u>All Other Costs to the Utility</u>	<u>Total Cost</u>
<u>DIRECT COSTS</u>			
5601 receivers @ \$76	\$425,676		
1 - 34.5 KV injection equipment (100 MVA)	40,000		
1 - 34.5 KV substation switchgear bay		\$ 30,000	
1 - bulk supply point metering	2,500		
(1 x 1) + (1 x 2) circuit leased line (15 circuit miles) @ \$60/circuit mile		180	
Control Center	<u>11,720</u>		
	\$479,896	\$ 30,180	\$510,076
Spares - 1 year operation			
56 - (1%) receivers	\$ 4,256		
1 lot injection equipment spares	20,000		
1 lot telemetering and control	700		
Total spares	\$ 24,956		\$ 24,956
<u>INDIRECT COSTS</u>			
Installation of 5601 receivers @ \$15		\$ 84,015	
Installation of 34.5 KV injection \$15,000 + 100 MH @ \$18		16,800	
Installation of control and telemetering 60 MH @ \$18		1,080	
Initial Tests - 270 MH @ \$18		4,860	
Contingency 15%		<u>16,013</u>	
		\$122,768	\$122,768
Total			<u>\$657,800</u>

Average Cost/Customer = \$117.44

EXHIBIT 1-F-V

DOE LOAD CONTROL STUDY - NON GENERATING UTILITIESCase #1 - Winter Peaking Urban UtilityDEVELOPMENT OF INSTALLED COSTS - VARIOUS GENERIC SYSTEMSSystem V - High Frequency Power Line Carrier

	<u>Amount Paid to Vendors</u>	<u>All Other Costs to the Utility</u>	<u>Total Cost</u>
<u>Direct Costs</u>			
5601 receivers @ \$95	\$ 532,095		
5601 load control relays @ \$25	140,025		
9 sector injection units @ \$9,700	87,300		
9 sets connection equipment @ \$500	4,500		
(9x1) + (1x2) circuit leased lines (55 circuit miles) @ \$60/circuit		\$ 660	
1 set bulk supply point metering	2,500		
1 control center	50,000		
	<u>\$ 771,420</u>	<u>\$ 660</u>	<u>\$ 772,080</u>
Spares - 1 year operation			
112 - (2%) end-use receiver	\$ 10,642		
56 - (1%) load control relays	1,400		
1 - sector injection unit	9,700		
1 - lot telemetering & control	5,200		
	<u>\$ 26,942</u>		<u>\$ 26,942</u>
<u>Indirect Costs</u>			
Installation of 5601 end-use receivers @ \$8		\$ 44,808	
Installation of 5601 load control relays @ \$15		84,015	
Installation of 9 sector injection units @ 16 MH		2,592	
Installation of control and telemetering @ 240 MH		4,320	
Initial test 450 MH		8,100	
Contingency 15%		21,575	
		<u>\$165,410</u>	<u>\$ 165,410</u>
Total			<u>\$ 964,432</u>
Average cost/customer \$172.19			

EXHIBIT 1-G

DOE LOAD CONTROL STUDY - NON GENERATING UTILITIESCase #1 - Winter Peaking Urban UtilityDEVELOPMENT OF ESTIMATED OPERATION & MAINTENANCE EXPENSEVarious Generic Systems

Page 1 of 2

	<u>MANHOURS</u>	<u>EXPENSE</u>
I. <u>RADIO</u>		
<u>Maintenance Labor</u>		
Xmitter 0.5 day/month - 2 men	96	
Receivers 112 per year at 1.0 MH each	112	
Complaints 10/month at 3 MH each	360	
Control 0.5 MH/month	6	
Total	574 @ \$18	\$ 10,332
Leased lines 10 circuit miles @ 3.25/m/mth =		390
Consumable spares 9,140 x 0.4		3,656
		<u>\$ 14,398</u>
II. <u>HYBRID</u>		
<u>Maintenance Labor</u>		
Xmitter (part of 2 way voice system)	0	
Receivers VHF 36/year (2 men 3 hrs + 1 man 1.0 hr)	252	
Receivers end use 56/year at 1.0 MH each	56	
Complaints 10/month at 3 MH each	360	
Control 0.5 MH/month	6	
Total	674 @ \$18	\$ 12,132
Leased Lines 10 circuit miles @ \$3.25/m/mth =		390
Consumable spares 7,080 x 0.4 =		2,832
		<u>\$ 15,354</u>
III. <u>PLC-LF RHYTHM</u>		
<u>Maintenance Labor</u>		
Receivers 56 year at 1.0 MH each	56	
Injection points - Inspection of 1 at 0.5 pay/month x 2 men each	96	
Complaints 15/month at 3 MH each	540	
Control 0.5 MH/month	6	
Total	698 @ \$18	\$ 12,564
Leased lines 15 circuit mile @ \$3.25/m/mth =		585
Consumable spares 15,780 x 0.4 =		6,312
		<u>\$ 19,461</u>
IV. <u>PLC-LF MULTIBIT CODE</u>		
<u>Maintenance Labor</u> (See above)		
Leased lines 15 circuit miles @ \$3.25/m/mth =		585
Consumable spares 24,956 x 0.4 =		9,982
		<u>\$ 23,131</u>

EXHIBIT 1-G

DOE LOAD CONTROL STUDY - NON GENERATING UTILITIESCase #1 - Winter Peaking Urban UtilityDEVELOPMENT OF ESTIMATED OPERATION & MAINTENANCE EXPENSEVarious Generic Systems

Page 2 of 2

	<u>MANHOURS</u>	<u>EXPENSE</u>
V. <u>PLC-HF</u>		
<u>Maintenance Labor</u>		
Receivers-112/year @ 1.5 MH each	168	
Injection Points - Inspection @	18	
- Replace 1/year @ 12 MH	12	
Complaints - 15/month @ 3 MH each	540	
Control - 2 MH/month	24	
Total	762 @ \$18	\$ 13,716
Leased Lines - 55 circuit miles @ \$3.25/m/mth =		2,145
Consumable spares 26,942 x 0.4 =		10,777
		<u>\$ 26,638</u>

EXHIBIT 1-H

DOE LOAD CONTROL STUDY - NON GENERATING UTILITIES

Case #1 - Urban Winter Peaking Utility

DEVELOPMENT OF CAPACITY COST SAVINGS WITH LOAD CONTROL

Purchased Power Costs Adjusted for 100% Water Heater Control

	ACTUAL DEMAND(1)				PRO FORM TO ELIMINATE TIME SWITCH CONTROL(2)				ESTIMATED CONTROLLED KVA(4)	ADJUSTED - ACTUAL BASIS			ADJUSTED - PRO FORMA BASIS		
	KW	KVA(3)	Billing KVA	Capacity Charges	KW	KVA(3)	Billing KVA	Capacity Charges		Billing KVA	Capacity Charges	Indicated Savings	Billing KVA	Capacity Charges	Indicated Savings
1974 - 11 Mo. Peak @ 80%			39,320				41,258			39,320			41,258		
1975 January	49,371	49,371	49,371	202,421	51,309	51,309	51,309	210,367	4,825	46,484	190,584	11,837	46,484	190,584	19,782
February	49,324	49,324	49,324	202,228	51,262	51,262	51,262	210,174	4,825	46,437	190,392	11,836	46,437	190,392	19,782
March	45,112	45,112	45,112	184,959	47,050	47,050	47,050	192,905	4,825	42,225	173,123	11,836	42,225	173,123	19,782
April	43,211	43,211	43,211	177,165	45,149	45,149	45,149	185,111	4,825	40,324	165,328	11,837	41,258*	169,158	15,953
May	38,640	39,835	39,835	163,324	40,093	41,333	41,333	169,465	3,619	39,320*	161,212	2,112	41,258*	169,158	307
June	45,570	46,979	46,979	192,614	47,023	48,477	48,477	198,756	3,619	44,858	183,918	8,696	44,858	183,918	14,838
July	46,054	47,478	47,478	194,660	47,507	48,976	48,976	200,802	3,619	45,357	185,964	8,676	45,357	185,964	14,838
August	48,929	50,442	50,442	206,812	50,382	51,940	51,940	212,954	3,619	48,321	198,116	8,696	48,321	198,116	14,838
September	40,136	40,136	40,354*	165,451	42,074	42,074	42,074	172,503	4,825	39,320*	161,212	4,239	41,258*	169,158	3,345
October	44,299	44,299	44,299	181,626	46,237	46,237	46,237	189,572	4,825	41,412	169,789	11,837	41,412	169,789	19,783
November	53,260	53,260	53,260	218,366	55,198	55,198	55,198	226,312	4,825	50,373	206,529	11,837	50,373	206,529	19,783
December	58,023	58,023	58,023	237,894	59,961	59,961	59,961	245,840	4,825	55,136	226,058	11,836	55,136	226,058	19,782
Total				2,327,520				2,414,761			2,212,225	115,295		2,231,947	182,814
11 Mo. Peak @ 80%			46,418				47,969			44,109					
1976 January	58,908	58,908	58,908	241,523	60,846	60,846	60,846	249,469	4,825	56,021	229,686	11,837			19,783
February	60,198	60,198	60,198	246,812	62,136	62,136	62,136	254,758	4,825	57,311	234,975	11,837			19,783
March	53,400	53,400	53,400	218,940	55,338	55,338	55,338	226,886	4,825	50,513	207,103	11,837			19,783
April	47,952	47,952	48,158*	197,448	49,890	49,890	49,890	204,549	4,825	45,849*	187,981	9,467	Same		16,568
May	40,930	42,196	48,158*	197,448	42,383	43,694	49,709*	203,807	3,619	45,849*	187,981	9,467			15,826
June	49,104	50,623	50,623	207,554	50,557	52,121	52,121	213,696	3,619	48,502	198,858	8,696	as		14,838
July	47,867	49,347	49,347	202,323	49,320	50,845	50,845	208,465	3,619	47,226	193,627	8,696			14,838
August	48,390	49,887	49,887	204,537	49,843	51,385	51,385	210,679	3,619	47,766	195,841	8,696	Actual		14,838
September	43,097	43,097	48,158*	197,448	45,035	45,035	49,709*	203,807	4,825	45,849*	187,981	9,467			15,826
October	47,686	47,686	48,158*	197,448	49,624	49,624	49,709*	203,807	4,825	45,849*	187,981	9,467			15,826
November	53,110	53,110	53,110	217,751	55,048	55,048	55,048	225,697	4,825	50,223	205,914	11,837			19,783
December	66,079	66,079	66,079	270,924	68,017	68,017	68,017	278,870	4,825	63,192	259,087	11,837			19,783
Total				2,600,156				2,684,490			2,477,015	123,141			207,475

- Notes: * Ratchet base = 80% of previous 11 month's maximum demand
 Water heater diversified demands assumed @ .8 KW and .6 KW for winter and summer respectively
 Demand Losses assumed @ 9% so that loss factor = $1/.91 = 1.0989$
 Equipment failure rate assumed @ 2%
- (1) From Company Data
 (2) There are presently 2,204 time switch controlled water heater installations.
 To eliminate the effect of present control, Winter: $2204 \times .8 \times 1.0989 = 1938 \text{ KW}$
 Summer: $2204 \times .6 \times 1.0989 = 1453 \text{ KW}$
- (3) Power factor for summer period (May-August) = 97%; Other months @ unity
 (4) There are presently 5601 water heaters of which 3397 are QR type
 Estimated controlled KVA winter = $5601 \times .8 \times 1.0989 \times .98 = 4825 \text{ KVA}$
 summer = $5601 \times .6 \times 1.0989 \times .98 = 3619 \text{ KVA}$

EXHIBIT 1-J
DOE LOAD CONTROL STUDY - NONGENERATING UTILITIES
Case #1 - Urban Winter Peaking Utility
DEVELOPMENT OF INCOME TAX AND DISPLACED EARNINGS FACTORS

DEVELOPMENT OF RATE BASE					DEVELOPMENT OF TAX BASE AND CALCULATED INCOME TAX							
INVESTMENT	AVERAGE BALANCE FOR YEAR			RETURN ON EQUITY @ 5.58%	BOOK DEPRECIATION	TAX DEPRECIATION	DEFERRED TAXES	INVESTMENT TAX CREDIT ADJUSTMENT	TAX BASE	CALCULATED TAX	INVESTMENT TAX CREDIT	NET INCOME TAX
	ACCUMULATED DEPRECIATION	ACCUMULATED DEFERRED TAXES	RATE BASE									
	(1)	(2)	(3)									
	(1)	(2)	(3)	(1)-(2)-(3)	(4)x.0558	(6)	(7)	(8)	(9)	5+6-7+8+9	(10)x $\frac{t}{1-t}$	
0	100.00											
1	100.00	3.33	4.77	91.90	5.13	6.67	25.00	9.53	9.33	5.66	6.13	10.00 -3.87
2	100.00	10.00	12.67	77.33	4.32	6.67	18.75	6.28	-0.67	-2.15	-2.33	-- -2.33
3	100.00	16.67	17.98	65.35	3.65	6.67	15.00	4.33	-0.67	-1.02	-1.11	-- -1.11
4	100.00	23.33	21.72	54.95	3.07	6.67	12.69	3.13	-0.67	-0.49	-0.53	-- -0.53
5	100.00	30.00	24.25	45.75	2.55	6.67	10.38	1.93	-0.67	0.10	0.11	-- 0.11
6	100.00	36.67	25.58	37.75	2.11	6.67	8.08	0.73	-0.67	0.76	0.82	-- 0.82
7	100.00	43.33	25.72	30.95	1.73	6.67	5.77	-0.47	-0.67	1.49	1.61	-- 1.61
8	100.00	50.00	24.65	25.35	1.41	6.67	3.46	-1.67	-0.67	2.28	2.47	-- 2.47
9	100.00	56.67	22.38	20.95	1.17	6.67	1.15	-2.87	-0.67	3.15	3.41	-- 3.41
10	100.00	63.33	19.22	17.45	0.97	6.67	--	-3.47	-0.67	3.50	3.79	-- 3.79
11	100.00	70.00	15.75	14.25	0.80	6.67	--	-3.47	-0.67	3.33	3.61	-- 3.61
12	100.00	76.67	12.28	11.05	0.62	6.67	--	-3.47	-0.67	3.15	3.41	-- 3.41
13	100.00	83.33	8.82	7.85	0.44	6.67	--	-3.47	-0.67	2.97	3.22	-- 3.22
14	100.00	90.00	5.35	4.65	0.26	6.67	--	-3.47	-0.67	2.79	3.02	-- 3.02
15	100.00	96.67	1.88	1.45	0.08	6.67	--	-3.47	-0.67	2.61	2.83	-- 2.83

DISPLACED EARNINGS FACTOR					INCOME TAX FACTOR				
	ACCUMULATED DEFERRED TAXES	DISPLACED EARNINGS @ 10.60%	PRESENT WORTH FACTOR	PRESENT WORTH	CURRENT	INCOME TAXES		PRESENT WORTH FACTOR	PRESENT WORTH
						DEFERRED	TOTAL		
1	4.77	0.51	.904159	0.46	-3.87	9.53	5.66	.904159	5.12
2	12.67	1.34	.817504	1.10	-2.33	6.28	3.95	.817504	3.23
3	17.98	1.90	.739153	1.40	-1.11	4.33	3.22	.739153	2.38
4	21.72	2.30	.668312	1.54	-0.53	3.13	2.60	.668312	1.74
5	24.25	2.57	.604261	1.55	0.11	1.93	2.04	.604261	1.23
6	25.58	2.71	.546348	1.48	0.82	0.73	1.55	.546348	0.85
7	25.72	2.73	.493985	1.35	1.61	-0.47	1.14	.493985	0.56
8	24.65	2.61	.446641	1.17	2.47	-1.67	0.80	.446641	0.36
9	22.38	2.37	.403835	0.96	3.41	-2.87	0.54	.403835	0.22
10	19.22	2.04	.365131	0.74	3.79	-3.47	0.32	.365131	0.12
11	15.75	1.67	.330137	0.55	3.61	-3.47	0.14	.330137	0.05
12	12.28	1.30	.298496	0.39	3.41	-3.47	0.06	.298496	0.02
13	8.82	0.93	.269888	0.25	3.22	-3.47	-0.25	.269888	-0.07
14	5.35	0.57	.244022	0.14	3.02	-3.47	-0.45	.244022	-0.11
15	1.88	0.20	.220634	0.04	2.83	-3.47	-0.64	.220634	-0.14
Total				13.12					15.56
Annuity Factor				.136008					.136008
Annual Equivalent				1.78					2.12

EXHIBIT 1-K

DOE LOAD CONTROL STUDY - NON GENERATING UTILITIES

Case #1 - Urban Winter Peaking Utility

DEVELOPMENT OF ANNUAL EQUIVALENT OPERATION & MAINTENANCE EXPENSES

Various Control Systems - Water Heater Control @ 100% Acceptance Rate

	OPERATION AND MAINTENANCE EXPENSE FOR GENERIC TYPE (1)(2)					PRESENT WORTH FACTOR (3)	PRESENT WORTH FOR GENERIC TYPE (1)				
	I	II	III	IV	V		I	II	III	IV	V
1975	14,398	15,354	19,461	23,131	26,638	.904159	13,018	13,882	17,596	20,914	24,085
1976	15,406	16,429	20,823	24,750	28,503	.817504	12,594	13,431	17,023	20,233	23,301
1977	16,484	17,579	22,281	26,483	30,498	.739153	12,184	12,994	16,469	19,575	22,543
1978	17,638	18,809	23,841	28,336	32,633	.668312	11,788	12,570	15,933	18,937	21,809
1979	18,873	20,126	25,509	30,320	34,917	.604261	11,404	12,161	15,414	18,321	21,099
1980	20,194	21,535	27,285	32,442	37,361	.546348	11,033	11,766	14,913	17,725	20,412
1981	21,608	23,042	29,206	34,713	39,976	.493985	10,674	11,382	14,427	17,148	19,748
1982	23,120	24,655	31,250	37,143	42,775	.446641	10,326	11,012	13,958	16,590	19,105
1983	24,738	26,381	33,438	39,743	45,769	.403835	9,990	10,654	13,503	16,050	18,483
1984	26,470	28,228	35,778	42,525	48,973	.365131	9,665	10,307	13,064	15,527	17,882
1985	28,323	30,204	38,283	45,502	52,401	.330137	9,350	9,971	12,639	15,022	17,300
1986	30,306	32,318	40,963	48,687	56,069	.298496	9,046	9,647	12,227	14,533	16,736
1987	32,427	34,580	43,830	52,095	59,994	.269888	8,752	9,333	11,829	14,060	16,192
1988	34,697	37,001	46,898	55,742	64,193	.244022	8,467	9,029	11,444	13,602	15,665
1989	37,126	39,591	50,181	59,644	68,687	.220634	8,191	8,735	11,072	13,159	15,155
							156,482	166,874	211,511	251,396	289,515
							.136008	.136008	.136008	.136008	.136008
							21,283	22,696	28,767	34,192	39,376

Annuity Factor - 10.6%/15 Yrs.

Annual Equivalent

NOTES: (1) Generic Types:

I - Radio

II - Hybrid Radio &
Power Line CarrierIII - Power Line Carrier
(Low Frequency-Rhythm)IV - Power Line Carrier
(Low Frequency-Multibit)V - Power Line Carrier
(High Frequency)

(2) O&M Expense escalated @ 7% per year

(3) Discount Rate = 10.6%

EXHIBIT 1-L

DOE LOAD CONTROL STUDY - NON GENERATING UTILITIESCase #1 - Urban Winter Peaking UtilityDEVELOPMENT OF ANNUAL EQUIVALENT CAPACITY COST SAVINGSWater Heater Control @ 100% Acceptance Rate

	<u>CAPACITY COST SAVINGS</u>		<u>PRESENT WORTH</u>	
	<u>Calculated</u>	<u>Projected @ 7% Escalation</u>	<u>Factor (1)</u>	<u>Amount</u>
1975	182,814		.904159	165,293
1976	207,475		.817504	169,612
1977		221,998	.739153	164,090
1978		237,538	.668312	158,749
1979		254,166	.604261	153,583
1980		271,957	.546348	148,583
1981		290,994	.493985	143,747
1982		311,364	.446641	139,068
1983		333,160	.403835	134,542
1984		356,481	.365131	130,162
1985		381,434	.330137	125,925
1986		408,135	.298496	121,827
1987		436,704	.269888	117,861
1988		467,273	.244022	114,025
1989		499,983	.220634	110,313
Total				<u>2,097,380</u>
Annuity Factor 10.6%/15 Years				.136008
Annual Equivalent of PW				<u><u>285,260</u></u>

Note: (1) Discount Rate = 10.6%

EXHIBIT 1-M

DOE LOAD CONTROL STUDY - NON GENERATING UTILITIESCase #1 - Urban Winter Peaking UtilitySUMMARY OF BENEFIT/COST RATIOS AND PAYBACK PERIODVarious Control Systems - Water Heater Control @ 100% Acceptance Rate

	I RADIO	II HYBRID RADIO & POWER LINE CARRIER	III Low Frequency Rhythm Keying	IV Low Frequency Multibit Code	V High Frequency (One Way)
<u>COST</u>					
Installed Cost	\$514,635	\$624,870	\$533,799	\$657,800	\$964,432
Fixed Charge Rate	16.19%	16.19%	16.19%	16.19%	16.19%
Annual Fixed Charges - Levelized	83,319	101,166	86,422	106,498	156,142
Operation & Maintenance Expenses (Annual Equivalent of Present Worth)	21,283	22,696	28,767	34,192	39,376
Total Annual Cost - Levelized	<u>\$104,602</u>	<u>\$123,862</u>	<u>\$115,189</u>	<u>\$140,690</u>	<u>\$195,318</u>
<u>BENEFIT</u>					
Annual Capacity Cost Savings by Reason of Water Heater Control - Levelized	<u>\$285,260</u>	<u>\$285,260</u>	<u>\$285,260</u>	<u>\$285,260</u>	<u>\$285,260</u>
<u>BENEFIT/COST RATIO</u>	<u>2.73</u>	<u>2.30</u>	<u>2.48</u>	<u>2.03</u>	<u>1.46</u>
<u>PAYBACK PERIOD</u>					
Cumulative Net Savings (Before Taxes) Exceed Installed Cost in	2.9 yrs.	3.5 yrs.	3.1 yrs.	3.8 yrs.	5.6 yrs.
Cumulative Net Savings (After Taxes) Exceed Installed Cost in	<u>3.4 yrs.</u>	<u>3.9 yrs.</u>	<u>3.5 yrs.</u>	<u>4.1 yrs.</u>	<u>6.0 yrs.</u>

EXHIBIT 1-NDOE LOAD CONTROL STUDY - NON GENERATING UTILITIESDetermination of Payback Period - Before and After TaxesCASE # 1 - URBAN WINTER PEAKING UTILITYVarious Control Systems - Water Heater Control @ 100% Acceptance Rate

	YEAR	INSTALLED COST	CAPACITY COST SAVINGS	OPERATING EXPENSES			NET SAVINGS BEFORE TAXES		INCOME TAX EFFECT				NET SAVINGS AFTER TAXES	
				O&M Expenses	Property Taxes	Total	For Year	Cumulative	Tax Depreciation	Taxable Income	Income Tax @ 52%	Investment Tax Credit	For Year	Cumulative
I. RADIO		514,635												
	1		182,814	14,398	11,579	25,977	156,837	156,837	128,639	28,198	14,663	(51,464)	193,638	193,638
	2		207,475	15,406	11,579	26,985	180,490	337,327	96,494	83,996	43,678	-	136,812	330,450
	3		221,998	16,484	11,579	28,063	193,935	531,262	77,195	116,740	60,705	-	133,230	463,680
	4		237,538	17,638	11,579	29,217	208,321	-	65,307	143,014	74,367	-	133,954	597,634
II. HYBRID		624,870												
	1		182,814	15,354	14,060	29,414	153,400	153,400	156,218	(2,818)	(1,465)	(62,487)	217,352	217,352
	2		207,475	16,429	14,060	30,489	176,986	330,386	117,163	59,823	31,108	-	145,878	363,230
	3		221,998	17,579	14,060	31,639	190,359	520,745	93,731	96,628	50,247	-	140,112	503,342
	4		237,538	18,809	14,060	32,869	204,669	725,414	79,296	125,373	65,194	-	139,475	642,817
III. L. F. Rhythm		533,799												
	1		182,814	19,461	12,010	31,471	151,343	151,343	133,450	17,893	9,304	(53,380)	195,419	195,419
	2		207,475	20,823	12,010	32,833	174,642	325,985	100,087	74,555	38,769	-	135,873	331,292
	3		221,998	22,281	12,010	34,291	187,707	513,692	80,070	107,637	55,971	-	131,736	463,028
	4		237,538	23,841	12,010	35,851	201,687	715,379	67,739	133,948	69,653	-	132,034	595,062
IV. L. F. Multibit		657,800												
	1		182,814	23,131	14,801	37,932	144,882	144,882	164,450	(19,568)	(10,175)	(65,780)	220,837	220,837
	2		207,475	24,750	14,801	39,551	167,924	312,806	123,338	44,586	23,185	-	144,739	365,576
	3		221,998	26,483	14,801	41,284	180,714	493,520	98,670	82,044	42,663	-	138,051	503,627
	4		237,538	28,106	14,801	43,137	194,401	687,921	83,475	110,926	57,682	-	136,719	640,346
	5		254,166	30,320	14,801	45,121	209,045	-	68,280	140,765	73,198	-	135,847	776,193
V. High Frequency		964,432												
	1		182,814	26,638	24,499	51,137	131,677	131,677	272,210	(140,533)	(73,077)	(108,884)	313,638	313,638
	2		207,475	28,503	24,499	53,002	154,473	286,150	204,157	(49,684)	(25,836)	-	180,309	493,947
	3		221,998	30,498	24,499	54,997	167,001	453,151	163,326	3,675	1,911	-	165,090	659,037
	4		237,538	32,633	24,499	57,132	180,406	633,557	138,734	41,672	21,669	-	158,737	817,774
	5		254,166	34,917	24,499	59,416	194,750	828,307	113,021	81,729	42,499	-	152,251	970,025
	6		271,957	37,361	24,499	61,860	210,097	1,038,404

CASE #2WINTER PEAKING - RURAL SYSTEM

In this case, load control is examined from the perspective of a rural electric coop in the East Central section of the country.

The utility covers a compact area approximately 30 miles square and relatively flat. Apart from a few small towns serving the rural communities, the most significant departure from a purely rural characteristic is the influence of a large city to the northeast of the area served. A growth of commuter residence is evident. The electrical network consists of eleven transformer substations, each of which feeds a 7 KV distribution network associated with it.

Power for the area is provided from two separate sources at 69 KV and 34.5 KV. By virtue of a combination of EHV line arrangements and the use of normally closed medium voltage tie lines between substations (served by common EHV networks), the area is in effect six electrically independent sub networks. There seems to be little reason to suspect that these conditions will change significantly over the next few years.

Typically, annual peak demands occur during the months of December or January and between the hours of 5:30 p.m. and 7:30 p.m. Currently, peak load reaches about 33 MW.

The system serves approximately 6900 residential customers of which 4692 or 68% have electric water heaters. The load control scenario posed for this utility investigates 5 alternative systems whereby this water heating load could be controlled so as to minimize the monthly peak demand upon which the capacity cost component of purchased power expense is based.

Load Control Strategy

A simulation similar to Case 1 was performed on the load curve of a winter peaking rural utility, to develop a load control strategy. As in Case 1, the controllable load consisted of water heaters only. Various segments of the system are served independently by individual suppliers. For illustrative purposes, load control strategy will be developed only for that portion of the service area supplied by Supplier A.

This utility had a system peak day load profile as shown in Exhibit 2-A. Peak demand was 24,400 KW at 7 PM. Maximum controllable load for that segment supplied by Supplier A was calculated to be 3,434 KW (3,986 water heaters x Peak diversified demand of 0.8 KW per water heater x the loss factor, 1.0989 x water heater switch success rate, .98).

As in the first case, a load curve net of water heating was constructed by subtracting out the product of the total number of water heaters and the diversified demand of each heater at each time interval (obtained from the diversified demand curve of a similar utility - see Exhibit 2-B).

The peak of the load profile curve with water heaters removed established the control target.

The first step in the control strategy was to divide the population of water heaters into ten equal groups. Groups were inhibited in a manner to minimize off-time while keeping the resultant load below the control target. Groups were then restored as soon as the load curve decayed to a point below the control target equivalent to the restore demands for one or more of the groups available. (The restore demand is, of course, an increasingly significant multiple of the initial demand depending upon the off time.) The inhibits and restore sequences were developed as shown in Exhibits 2-C and 2-D. Restore demand curves for each group

were calculated using data derived from the Detroit Edison test shown in section III of this report.

The resultant load profiles showing the difference with and without control for the system peak day are shown in Exhibit 2-E. This figure also illustrates the "cause" of the change in system load profile, i.e., the change in the total water heater load on the system.

Note the high proportion of payback in this case relative to the Winter Peaking Urban Utility (Case 1). This can be attributed to two complementary factors: system load is relatively low and it is mostly residential. Water heaters are therefore a much larger proportion of the total load than in Case 1. It takes the system a lot longer to restore this larger segment without creating new secondary peaks.

In summary, the load control strategy for the illustrated portion of Case 2, a winter peaking rural utility consisted of controlling 3,986 water heaters in ten groups for an average inhibit time of 6 hours and 8 minutes. The longest off time was 7 hours and 45 minutes. The controllable load represented 13.6% of the system peak.

Development of Control System Costs

Control costs are developed for each of five generic types of control systems, and, for illustrative purposes, both costs and benefits are established on the basis of 100% acceptance rate, i.e., agreement by all 4,692 water heater customers (the total number served from both supply sources) to accept such controls. Consideration of system economics at lower acceptance levels is treated as a sensitivity analysis.

1. The Cost of Acquiring and Installing Control Apparatus

Installed system costs include both direct and indirect charges representing actual costs due vendors or other costs incurred by the utility in connection with the acquisition or installation of control facilities. Details supporting the development of overall installed costs for each of five generic types of control system applied in this analysis are included in Exhibit 2-F. Each estimate used as a basis the actual conditions prevailing at the location under study both in terms of system configuration and physical requirements. Pertinent features of alternative types of installation in the specific operating environment investigated are as follows:

- a. Radio - The topography of the area is suitable for radio control from a single transmitter. Since the utility already has a two-way VHF voice communication system in place, location of the load control transmitter at the same location will permit cost savings represented by joint use of transmitter housing, power supply and the antenna tower. The present location of these facilities appears to be a feasible site for load control transmission, and, consequently, we have recognized these savings in the cost estimate developed in

Exhibit 2-F-I. Total estimated costs for a Radio Control System are as follows:

Radio Control System

Direct costs including spares	\$363,340
Indirect costs including contingencies	87,271
Total installed cost	<u>\$450,611</u>

- b. Hybrid: Radio and Power Line Carrier - The radio portion of this system carries with it the same cost savings recognized above. In addition, shared use of the VHF voice transmitter appears feasible. In spite of this joint use benefit, hybrid system economics suffer in this environment because of the rural nature and resultant sparse customer density characteristic of the service area. Since, on average, only 1.2 customers are served from each distribution transformer, individual customers must bear a significant portion of the cost of each VHF receiver and carrier current receiver. The inherent advantage of multiple (up to 8) control and alarm channels per transformer secondary is essentially voided by the sparse distribution of customers.

Economic analysis employing the hybrid system has, however, been carried to completion. Consequently, costs associated with the system and its installation are detailed in Exhibit 2-F-II and are summarized below:

Hybrid Control System

Direct costs including spares	\$679,055
Indirect costs including contingencies	47,878
Total installed cost	<u>\$896,933</u>

- c. Low Frequency Power Line Carrier - The network is fed from a number of bulk supply points and while some interconnections on the medium voltage side exist, the network does contain isolated sections. It was recognized that a larger number of injection points would involve cost penalties but it was judged that for reliability purposes, each network section not interconnected at the distribution voltage level should be provided with an individual injection point.

Injection at the transmission voltage, utilizing the higher voltage system as the communication path, was considered to be inadvisable since the transmission system is not under the control of the distribution authority and is subject to change without notice. The net result may be, at worst, a signal path failure to part of the system, and, at best, a reduction in signal strength due to de-tuning the injection equipment. This problem is aggravated where portions of the system are fed from different sources.

A significant difference in cost is apparent between the simple rhythm code and the multibit binary code equipment. With the comparatively small number of potentially controllable customers, there appears to be little merit in incurring the additional costs of the multiple code system since the fifty commands available with the rhythm system should be adequate.

Comparative cost estimates for the two low frequency systems reviewed are detailed in Exhibits 2-F-III and 2-F-IV respectively. For reference,

total individual costs are summarized below:

	<u>LF POWER LINE CARRIER</u>	
	<u>Rhythm</u>	<u>Multibit</u>
Direct costs including spares	\$580,225	\$660,154
Indirect costs including contingencies	130,700	133,681
Total installed cost	<u>\$710,925</u>	<u>\$793,835</u>

- d. High Frequency Power Line Carrier - Application of the high frequency system with its requirement for injection at the medium voltage level on this type of system (rural) resulted in a conflict between the substation installed and line installed types of sector injection units. The use of partially loaded (75% capacity) line units was assumed resulting in a somewhat more economic installation. As a conservative measure, connection of the injection units to the central control is assumed to be via individual leased telephone lines although it is recognized that shared use is probably more realistic.

Although the high frequency system lends itself to two way communications and the ancillary functions permitted thereby, its use in this analysis is restricted to load control. There is no question but that shared use by the two way systems' attendant functions would contribute to the economics of high frequency system utilization. However, a decision to implement one or more of the systems' ancillary capabilities is very site specific and has not been assumed in costs developed in Exhibit 2-F-V and summarized below or subsequently in the establishment

of system benefits.

High Frequency Power Line Carrier

Direct costs including spares	\$747,288
Indirect costs including contingencies	182,615
Total installed cost	<u>\$929,903</u>

For each control system employed, a common central control readout and logic for detection of peak load conditions and initiation of load control action is assumed. It is a characteristic of the service area that it consists effectively of six electrically independent distribution areas. Remote telemetering from each of the six bulk supply points provides data for central control via leased telephone lines and total system demands are available to estimate the probability of an approaching system peak.

2. Operation and Maintenance Expense

Because of the relatively few points under control, it is not likely that any Company personnel need be exclusively dedicated to the operation of any of the control systems. By their nature, operation costs would consist primarily of charges for leased telephone lines or those associated with a microwave channel as applicable for the respective systems. Anticipated maintenance costs consist primarily of personnel charges and consumable spares. Average annual O&M expense estimates for each generic control system type are developed in Exhibit 2-G and are summarized as follows:

<u>Control System</u>	<u>Estimated Average Annual Operation & Maintenance Expense</u>
I. Radio	\$18,740
II. Hybrid	18,936
III. LF Power Line Carrier - Rhythm	34,866
IV. LF Power Line Carrier - Multibit	37,541
V. HF Power Line Carrier	31,865

Development of Estimated Capacity Cost Savings

By definition, each of the utilities considered in this analysis is non-generating, that is dependent upon external sources for power supply. It is therefore evident that the overwhelming benefit of load control will be reflected in reduced capacity charges for purchased power since under the control strategy formulated, overall energy consumption will remain relatively unaffected by water heater control and consequently energy cost differentials will be negligible.

Load studies undertaken to establish diversified water heater demands during system peak hours indicate .8 KW per water heater in the winter months and .6 KW in summer periods to be a conservative estimate. These seasonal loads are adopted for purposes of this analysis.

In order to extrapolate control point demands to the point of wholesale delivery to the system, distribution losses must be recognized. For the subject utility, system losses under peak conditions represent approximately 9% of delivered kilowatts. Finally, it must be anticipated that some portion of water heater controls may not be operational at any given time. In recognition of this factor, a 2% failure rate is incorporated in the development of total potentially controllable water heating loads. This determination may then be expressed as:

$$C = \frac{ND(1-F)}{1-L}$$

Where:

C = Controlled Water Heater Load
 N = Number of Controlled Water Heaters
 D = Diversified Demand per Water Heater
 F = Failure Rate
 L = System Losses

Substituting values as indicated above, potentially controllable water heater demands during winter months is established as:

$$C = \frac{(4,692) (.8KW) (1-.02)}{(1-.09)} = \underline{\underline{4,042KW}}$$

All factors remain the same for summer months except the diversified demand:

$$C_s = \frac{(4,692)(.6KW)(1-.02)}{(1+.09)} = \underline{\underline{3,032 \text{ KW}}}$$

As previously indicated, power is supplied to the coop by two different generating systems, one of which supplies approximately 85% of the coop's total requirements and other provides the remaining 15%.

The pro/rata controllable load at the billing point for each supplier is then:

	<u>Supplier A</u>	<u>Supplier B</u>
Diversified Water Heater Demand-Winter	3434 KW	608 KW
Diversified Water Heater Demand-Summer	2576 KW	456 KW

Supplier A's wholesale rate provides for a demand charge of \$5.04 per KW while Supplier B provides capacity at a cost of \$3.25 per KVA. A 60% demand ratchet based on the peak demand occurring during the preceding twelve month period applies in each instance.

Capacity charge savings resulting from water heater control are calculated in Exhibit 2-H on the basis of adjusted year 1975 loads serviced by each supplier.

Evaluation of Water Heater Control Costs and Benefits

The methodology proposed for benefit/cost analysis is predicated on a consideration of relative annual or annual equivalent costs and/or benefits as levelized. A further basic consideration of the proposed methodology is that it takes its perspective from the viewpoint of the ultimate consumer's revenue requirements. Accordingly, control system costs are translated into annual fixed charges representing levelized costs to the ratepayer in the form of debt service, depreciation and property taxes.

Fixed Charge Rate

The model for the Winter Peaking - Rural System case is an electric cooperative. Consequently, the cost of money component of the fixed charge rate is based on

the interest rate charged for REA type loans. Currently, the charge for such loans is generally 5% and this level is adopted in this analysis.

Depreciation in the context of a fixed charge rate is established as the sinking fund charge indicated at an interest (discount) rate equal to the cost of money over the estimated service life of the investment. This may be expressed by the following formula:

$$D = \frac{(1-s)i}{(1+i)^n - 1}$$

Where:

i = interest (discount) rate
n = service life
S = salvage value

Then, for a discount rate equal to the cost of money (5.00%) from above, and service life estimated at 15 years and zero salvage:

$$D = \frac{.05}{(1.05)^{15} - 1} = \frac{.05}{1.0789} = .0463 \text{ or } \underline{\underline{4.63\%}}$$

The cost of money and sinking fund depreciation together constitute the capital recovery factor.

Based upon an analysis of actual tax amounts, property taxes are estimated at a fixed annual level of 0.80% of investment.

In summary, the Fixed Charge Rate developed for application in Case #1 is then:

Case #1 Fixed Charge Rate

Cost of Money	5.00%
Depreciation	4.63
Property Taxes	0.80
Fixed Charge Rate	<u><u>10.43%</u></u>

Development of Levelized Annual Fixed Charges

Levelized annual fixed charges for each generic type of control system are developed as the product of individual Installed Cost estimates and the Fixed Charge Rate as developed above:

	GENERIC TYPE				
	I (Radio)	II (Hybrid)	III (LF-Rhythm)	IV (LF-Multibit)	V (HF-One Way)
Installed Cost	\$450,611	\$896,933	\$710,925	\$793,835	\$929,903
Fixed Charge Rate	10.43%	10.43%	10.43%	10.43%	10.43%
Levelized Fixed Charges	\$ 46,999	\$ 93,550	\$ 74,149	\$ 82,797	\$ 96,989

It should be noted that for this illustrative case, we have assumed a 15 year life and zero salvage value for each generic type. Any variation in either factor would obviously result in a different Fixed Charge Rate. The purpose of the methodology proposed is, in fact, to provide a valid basis for comparison when such differences exist as between generic types.

Development of Levelized Annual O&M Expense

Current (1975) levels of operation and maintenance expense estimates have been developed above for each generic type control system. It is likely, however, that, because of wage and other price adjustments, the level of annual O&M expense will escalate over the life cycle assumed for each control system. To account for this probability, each expense stream as developed in Exhibit 2-J includes escalation at an estimated level of 7% per annum through 1989, the fifteenth year of operation.

Under the proposed Benefit/Cost methodology, O&M expense is developed as the annual equivalent of the present worth of alternative expense streams. Again, since in the instant case the same service life (15 years) is assumed for each system, the necessity for this treatment is not as apparent. However, for illustrative purposes, the procedure has been carried out in Exhibit 2-J. The

Present Worth Factor for each year as applied to yearly expense in order to develop present worth is the result of the following formula:

$$PWF_n = \frac{1}{(1+i)^n}$$

Where: PWF_n = Present Worth Factor for Year n
 i = Discount Rate (in this Case 10.60%)
 n = year

Then: $PW = \sum_{n=1}^{15} \frac{E_n}{(1+i)^n}$ where E_n = yearly expense

Total Present Worth for each O&M expense stream is further shown in Exhibit 2-B. In order to express the respective amounts in terms of annual equivalents, an annuity factor is applied. The annuity factor results from the following formula:

$$AF = \frac{i (1+i)^n}{(1+i)^n - 1} = .096342, \text{ where } i = .05 \text{ and } n = 15$$

On an annual equivalent basis, the O&M expense component for each generic system is then:

	GENERIC TYPE				
	I	II	III	IV	V
Present Worth of Annual Expense	\$306,533	\$309,738	\$570,306	\$614,061	\$521,218
Annuity Factor	.096342	.096342	.096342	.096342	.096342
Annual Equivalent	<u>\$ 29,532</u>	<u>\$ 29,841</u>	<u>\$ 54,944</u>	<u>\$ 59,160</u>	<u>\$ 50,215</u>

Development of Levelized Capacity Cost Savings

For purposes of this analysis, load control system benefits are equated to savings in the capacity cost component of purchased power. The determination of current savings levels has been previously discussed and is detailed in Exhibit 2-H. As with other operating expenses, it is reasonable to assume that purchased power expense; and hence, capacity cost levels would continue to escalate in the future.

Recognizing this factor and applying the same technique previously described for O&M Expenses, the annual equivalent of the present worth of future capacity cost savings is developed as shown in Exhibit 2-K. Levelized annual capacity cost savings are calculated at \$326,697.

Summary of Costs and Benefits and Development of Benefit/Cost Ratio and Payback Periods

Exhibit 2-L summarizes levelized annual costs and capacity cost savings for each load control system type analyzed.

The Benefit/Cost Ratio is favorable in each instance as further demonstrated in Exhibit 2-L and summarized below:

	GENERIC TYPE				
	I	II	III	IV	V
Benefit/Cost Ratio	4.27	2.65	2.53	2.30	2.22

As a further measure of project viability, the Payback Period defined as the period necessary to recoup project costs through accumulated net savings, is developed for each system analyzed in Exhibit 2-M. Payback Periods are summarized in Exhibit 2-L.

Sensitivity Analyses

The Benefit/Cost Ratios developed above are predicated, among other things, upon

1. 100% Acceptance Rate by Water Heater Customers
2. Escalation of future Capacity Cost Savings @ 7% p a

Obviously, actual circumstances could depart from those assumptions indicated.

In order to measure the impact of variations in either of these analysis components, we have prepared Exhibit 2-N to demonstrate levelized costs and benefits at acceptance rates varying from 0 to 100%. For this purpose, Load Control

System costs were separated between fixed (central facilities, etc.) and variable (receivers, unit installation, etc.) components with the fixed portion applying even at 0% acceptance and variable costs incrementing with additional connections. It should be noted that this graph was prepared on the basis of specific data for the case under analysis and should not be construed as being a general representation.

Exhibit 2-F also depicts capacity cost savings at various acceptance levels without escalation. It may be seen that even on this basis, favorable benefit/cost ratios would result in each case with minimum acceptance rates ranging from approximately 10% for System I to approximately 55% for System IV.

Customer Incentives

On a break-even basis, monthly customer incentive could be offered at a maximum level represented by the following:

$$CI = \frac{.0833 (B_1 - C_1)}{NA}$$

Where CI = Customer incentive
 B₁ = Annual Equivalent Benefit for Generic Type 1
 C₁ = Annual Equivalent Cost for Generic Type 1
 N = Number of Water Heater Customers
 A = Acceptance Rate expressed as decimal

From data developed above, maximum monthly customer incentive for the radio control system at the 100% acceptance rate would then be:

$$CI = \frac{.0833(326,697-76,531)}{4,692 \times 1.00} = \frac{20,839}{4,692} = \underline{\underline{\$4.44 \text{ per month}}}$$

EXHIBIT 2A
CASE STUDY 2
WINTER PEAKING RURAL UTILITY
SYSTEM PEAK DAY LOAD PROFILE

EXHIBIT 2B
CASE STUDY 2
WINTER PEAKING RURAL UTILITY
TYPICAL WINTER LOAD PROFILE - WATER HEATER

EXHIBIT 2-C

WINTER PEAKING RURAL UTILITY - CONTROL SEQUENCE AT PEAK DAY

GIVEN: System Peak: 24,450 KW at 7 PM
 Max. Controllable Load: 3,340 KW (3,986 Water Heaters x 0.8 KW/heater x 1.0989 Loss Factor x .98)
 Control Target: 21,110 KW (24,450 - 3,340)
 Group Size: 400 Water Heaters

INHIBIT SEQUENCE

TIME OF INHIBIT	MIN. DEMAND REDUCTION NEC. IN NEXT 15 MIN.	GROUP DEMAND AT TIME OF INHIBIT	TOTAL NO. GROUPS INHIBITED	TOTAL LOAD SHED	RESULTANT DEMAND AT THIS TIME
4:45	375 KW	$400 \times 1.09 \times .98 \times .56 = 241 \text{ KW}$	2	482 KW	20,500
5:00	950 KW	$400 \times 1.09 \times .98 \times .58 = 250 \text{ KW}$	4	1,000 KW	20,400
5:15	1,750 KW	$400 \times 1.09 \times .98 \times .60 = 257 \text{ KW}$	7	1,800 KW	20,200
5:30	2,250 KW	$400 \times 1.09 \times .98 \times .63 = 267 \text{ KW}$	9	2,400 KW	20,400
5:45	2,650 KW	$400 \times 1.09 \times .98 \times .66 = 284 \text{ KW}$	10	2,840 KW	20,500

5:45 to 9:00 ALL GROUPS OFF (3 Hours 15 Min.)

RESTORE SEQUENCE

TIME OF RESTORE	RESTORABLE LOAD	GROUP DEMAND AT TIME OF RESTORE	NO. GROUPS RESTORED	GROUP OFF TIME	CUMULATIVE RESTORED DEMAND	RESULTANT SYSTEM LOAD
9:00	1,000 KW	$400 \times 1.09 \times .98 \times .56 \times 4.15 = 1,021 \text{ KW}$	1	4:15	1,021	21,000
9:45	1,200 KW	$400 \times 1.09 \times .98 \times .56 \times 4.3 = 1,058 \text{ KW}$	1	5:00	1,850	20,900
10:15	1,000 KW	$400 \times 1.09 \times .98 \times .58 \times 4.35 = 1,170 \text{ KW}$	1	5:15	2,350	20,800
10:45	1,350 KW	$400 \times 1.09 \times .98 \times .58 \times 4.5 = 1,150 \text{ KW}$	1	5:45	2,950	20,800
11:15	1,600 KW	$400 \times 1.09 \times .98 \times .50 \times 4.6 = 1,200 \text{ KW}$	1	6:00	3,700	20,700
11:30	1,200 KW	$400 \times 1.09 \times .98 \times .60 \times 4.65 = 1,200 \text{ KW}$	1	6:15	4,200	21,000
12:00	1,300 KW	$400 \times 1.09 \times .98 \times .60 \times 4.75 = 1,250 \text{ KW}$	1	6:45	4,700	21,000
12:30	1,400 KW	$400 \times 1.09 \times .98 \times .63 \times 4.8 = 1,330 \text{ KW}$	1	7:00	5,100	21,000
1:00	1,500 KW	$400 \times 1.09 \times .98 \times .63 \times 4.85 = 1,350 \text{ KW}$	1	7:30	5,400	20,900
1:30	1,400 KW	$400 \times 1.09 \times .98 \times .66 \times 4.95 = 1,400 \text{ KW}$	1	7:45	5,800	21,100

EXHIBIT 2E
CASE STUDY 2
WINTER PEAKING RURAL
WATER HEATER CONTROL - EFFECT ON LOAD PROFILE

EXHIBIT 2-F-I

DOE LOAD CONTROL STUDY - NON GENERATING UTILITIESCase #2 - Winter Peaking Rural UtilityDEVELOPMENT OF INSTALLED COSTS - VARIOUS GENERIC SYSTEMSSystem I - Radio

	Amount Paid to Vendors	All Other Costs to the Utility	Total Cost
<u>DIRECT COSTS</u>			
4692 receivers @ \$70	\$328,440		
1 transmitter and antenna \$7000	7,000		
1 antenna tower - joint use	-		
1 transmitter land line - joint use	-		
6 sets - Bulk supply point metering @ \$2500	15,000		
6 x 2 circuit leased lines (140 circuit miles) @ \$60/circuit mile		\$ 720	
1 Control center	4,000		
	<u>\$354,440</u>	<u>\$ 720</u>	\$355,160
Spares - 1 year operation			
94 - (2%) of receivers	\$ 6,580		
1 lot transmitter spares	700		
1 lot telemetering and control	900		
Total spares	<u>\$ 8,180</u>		\$ 8,180
<u>INDIRECT COSTS</u>			
Installation of 4692 receivers @ \$15		\$ 70,380	
Installation of transmitter @ 50 MH		900	
Installation of control, telemetering @ 128 MH		2,304	
Initial test 128 MH @ \$18		2,304	
Contingency 15%		11,383	
		<u>\$ 87,271</u>	<u>\$ 87,271</u>
Total			<u>\$450,611</u>
Average Cost/Customer - \$96.04			

EXHIBIT 2-F-II

DOE LOAD CONTROL STUDY - NON GENERATING UTILITIESCase #2 - Winter Peaking Rural UtilityDEVELOPMENT OF INSTALLED COSTS - VARIOUS GENERIC SYSTEMSSystem II - Hybrid: Radio and Power Line Carrier

	<u>Amount Paid to Vendors</u>	<u>All Other Costs to the Utility</u>	<u>Total Cost</u>
<u>DIRECT COSTS</u>			
4692 end-use receivers @ \$45	\$211,140		
3910* VHF receiver @ \$110	430,100		
1 transmitter complete - joint use	-		
1 master controller @ \$6000	6,000		
6 bulk supply point metering @ \$2500	15,000		
6 x 2 circuit leased lines (140 circuit miles) @ \$60/circuit mile		\$ 720	
1 control center	4,500		
	<u>\$666,740</u>	<u>\$ 720</u>	<u>\$667,460</u>
Spares - 1 year operation			
47 - (1%) end-use receivers	\$ 2,115		
78 - (2%) VHF receivers	8,580		
1 lot telemetering and control	900		
Total spares	<u>\$ 11,595</u>		<u>\$ 11,595</u>
<u>INDIRECT COSTS</u>			
Installation of 4692 end-use receivers @ \$15		\$ 70,380	
Installation of 3910 VHF receivers @ 1.5 MH		105,570	
Installation of control and telemetering @ 128 MH		2,304	
Initial test 4150 x 0.15 = 622 MH		11,205	
Contingency 15%		28,419	
		<u>\$217,878</u>	<u>\$ 47,878</u>
Total			<u><u>\$896,933</u></u>
Average Cost/Customer \$191.16			
*6900 customers, 5800 transformers average 1.2 Customer/Transformer			
No. of VHF receivers $\frac{4692}{1.2} = 3910$			

EXHIBIT 2-F-III

DOE LOAD CONTROL STUDY - NON GENERATING UTILITIESCase #2 - Winter Peaking Rural SystemDEVELOPMENT OF INSTALLED COSTS - VARIOUS GENERIC SYSTEMSSystem III - LF Power Line Carrier, Rhythm Keying

	Amount Paid to Vendors	All Other Costs to the Utility	Total Cost
<u>DIRECT COSTS</u>			
4692 receivers @ \$55	\$258,060		
6 sets - 7KV injection equipment @ \$45,000	270,000		
6 sets - 7KV bus connections and feeder @ \$2500		\$ 15,000	
6 bulk supply point metering @ \$2500	15,000		
6 x 3 circuit leased lines (210 circuit miles) @ \$60/Circuit mile		1,080	
1 control center	<u>7,000</u>		
	\$550,060	\$ 16,080	\$566,140
Spares - 1 year operation			
47 - (1%) receivers	\$ 2,585		
1 lot injection equipment spares	10,000		
1 lot telemetering and control	<u>1,500</u>		
Total spares	\$ 14,085		\$ 14,085
<u>INDIRECT COSTS</u>			
Installation of 4692 receivers @ \$15		\$ 70,380	
Installation of injection equipment - 6 (240 MH + \$1500)		34,920	
Installation of control and telemetering @ 128 MH		2,304	
Initial tests @ 336 MH		6,048	
Contingency 15%		<u>17,048</u>	
		\$130,700	\$130,700
Total			<u>\$710,925</u>
Average Cost/Customer \$151.52			

EXHIBIT 2-F-IV

DOE LOAD CONTROL STUDY - NON GENERATING UTILITIESCase #2 - Winter Peaking Rural SystemDEVELOPMENT OF INSTALLED COSTS - VARIOUS GENERIC SYSTEMSSystem IV - LF Power Line Carrier, Multibit Code

	Amount Paid to Vendors	All Other Costs to the Utility	Total Cost
<u>DIRECT COSTS</u>			
4692 receivers @ \$76	\$356,592		
6 sets - 7KV injection equipment @ 40,000	240,000		
6 sets - 7KV bus connection and feeder @ \$2500		\$ 15,000	
6 bulk supply point metering \$2500	15,000		
6 x 3 circuit based lines (210 circuit miles) @ \$60/circuit mile		1,080	
1 control center	<u>11,710</u>		
	\$623,302	\$ 16,080	\$639,382
Spares - 1 year operation			
47 - (1%) receivers	\$ 3,572		
1 lot injection equipment spares	14,000		
1 lot telometer and control	<u>3,200</u>		
Total spares	\$ 20,772		\$ 20,772
<u>INDIRECT COSTS</u>			
Installation of 4692 receivers @ \$15		\$ 70,380	
Installation of injection equipment - 6 (240 MH + \$1500)		34,920	
Installation of control and telemetering @ 128 MH		2,304	
Initial tests @ 480 MH		8,640	
Contingency 15%		<u>17,437</u>	
		\$133,681	\$133,681
Total			<u>\$793,835</u>
Average Cost/Customer \$169.19			

EXHIBIT 2-F-VDOE LOAD CONTROL STUDY - NON GENERATING UTILITIESCase #2 - Winter Peaking Rural SystemDEVELOPMENT OF INSTALLED COSTS - VARIOUS GENERIC SYSTEMSSystem V - High Frequency Power Line Carrier

	<u>Amount Paid to Vendors</u>	<u>All Other Costs to the Utility</u>	<u>Total Cost</u>
<u>Direct Costs</u>			
4692 receivers @ \$95	\$ 445,740		
4692 load control relays @ \$25	117,300		
9 sector injection units @ \$9,700	87,300		
9 sets 7KV connection equipment @ \$400		\$ 3,600	
(9x1) + (6x2) circuit leased lines (220 circuit miles) @ \$60		1,260	
6 sets - bulk supply point metering @ \$2500	15,000		
1 - Control center	50,000		
	<u>\$ 715,340</u>	<u>\$ 4,860</u>	<u>\$ 720,200</u>
Spares - 1 year operation			
94 - (2%) end use receivers	\$ 8,915		
47 - (1%) load control relays	1,173		
1 - sector injection unit	9,700		
1 lot - telemetering and control			
Total Spares	<u>\$ 27,088</u>		<u>\$ 27,088</u>
<u>Indirect Costs</u>			
Installation of 4692 end use receivers @ \$8		\$ 37,536	
Installation of 4692 load control relays @ \$22		103,224	
Installation of 9 sector injection units @ 16 MH		2,592	
Installation of control and telemetering @ 408 MH		7,344	
Initial test @ 450 MH		8,100	
Contingency 15%		23,819	
		<u>\$182,615</u>	<u>\$ 182,615</u>
Total			<u><u>\$ 929,703</u></u>

Average cost/controlled customer = \$198.15

EXHIBIT 2-G

DOE LOAD CONTROL STUDY - NON GENERATING UTILITIESCase #2 - Winter Peaking Rural UtilityDEVELOPMENT OF ESTIMATED OPERATION & MAINTENANCE EXPENSEVarious Generic Systems

Page 1 of 2

	<u>MANHOURS</u>	<u>EXPENSE</u>
I. <u>RADIO</u>		
<u>Maintenance Labor</u>		
Xmitter 0.5 day/month x 2 men	96	
Receivers 94/year at 1.0 MH each	94	
Complaints 10/month at 3 MH each	360	
Control 0.5 MH/month	6	
Total	556 @ \$18	\$ 10,008
Leased lines 140 circuit miles @ 3.25/m/mth =		5,460
Consumable spares 8,180 x 0.4 =		3,272
		<u>\$ 18,740</u>
II. <u>HYBRID</u>		
<u>Maintenance Labor</u>		
Xmitter (part of 2-way voice system)	0	
Receivers VHF - 78/year at 1.0 MH each	78	
Complaints 10/month at 3 MH each	360	
Control 0.5 MH/Month	6	
Receivers end-use 47 @ 1.0 MH each	47	
Total	491 @ \$18	\$ 8,838
Leased lines 140 circuit miles @ \$3.25/m/mth =		5,460
Consumable spares 11,595 x 0.4 =		4,638
		<u>\$ 18,936</u>
III. <u>PLC-LF RHYTHM</u>		
<u>Maintenance Labor</u>		
Receivers 47/year at 1.0 MH each	47	
Injection points-inspection of 6 at		
0.5 day/month per point x 2 men each	576	
Complaints 15/month at 3 MH each	540	
Control 0.5 MH/month	6	
Total	1,169 @ \$18	\$ 21,042
Leased lines 210 circuit mile @ \$3.25/m/mth =		8,190
Consumable spares 14,085 x 0.4 =		5,634
		<u>\$ 34,866</u>
IV. <u>PLC-LF MULTIBIT CODE</u>		
<u>Maintenance Labor</u> (See above)		
Leased lines 210 circuit miles @ \$3.25/m/mth =		8,190
Consumable spares 20,772 x 0.4 =		8,309
		<u>\$ 37,541</u>

EXHIBIT 2-G

DOE LOAD CONTROL STUDY - NON GENERATING UTILITIESCase #2 - Winter Peaking Rural UtilityDEVELOPMENT OF ESTIMATED OPERATION & MAINTENANCE EXPENSEVarious Generic Systems

Page 2 of 2

	<u>MANHOURS</u>	<u>EXPENSE</u>
V. <u>PLC-HF (One Way)</u>		
<u>Maintenance Labor</u>		
Receivers - 94/year @ 1.5 MH each	141	
Injection points - inspection of 9		
@ 2 MH/point/year	18	
Injection units - replace/repair 1/year	12	
Complaints - 15/month @ 3 MH each	540	
Control - 2 MH/month	24	
Total	735 @ \$18	\$ 13,230
Leased lines - 200 circuit miles @ \$3.25/m/mth =		7,800
Consumable spares - 27,088 x 0.4 =		10,835
		<u>\$ 31,865</u>

EXHIBIT 2-H

DOE LOAD CONTROL STUDY - NON-GENERATING UTILITIES

Case #2 - Winter Peaking Rural Utility

DEVELOPMENT OF CAPACITY COST SAVINGS WITH LOAD CONTROL

Purchased Power Costs Adjusted for 100% Water Heater Control

		LOAD SERVED BY SUPPLIER A								LOAD SERVED BY SUPPLIER B								TOTAL	
		KW Demand, No Control		KW Demand, With Control		Demand Charges @ \$5.04/KW		Indicated Savings	KW Demand Actual	KVA No Control		KVA With Control		KVA Charges @ \$3.25/KVA		Indicated Savings	TOTAL SAVINGS		
		Actual	Billing	Actual	Billing	No Control	With Control			Actual	Actual	Billing	Actual	Billing	No Control			W/Control	
1975	Jan.	24,334	24,334	20,900	20,900	\$ 122,643	\$ 105,336	\$ 17,307	6,168	6,227	6,227	5,619	5,619	\$ 20,238	\$ 18,262	\$ 1,976	\$ 19,283		
	Feb.	24,469	24,469	21,035	21,035	123,324	106,016	17,308	6,180	6,288	6,288	5,680	5,680	20,436	18,460	1,976	19,284		
	Mar.	21,955	21,955	18,521	18,521	110,653	93,346	17,307	6,270	6,429	6,429	5,821	5,821	20,894	18,918	1,976	19,283		
	Apr.	20,969	20,969	17,535	17,535	105,684	88,376	17,308	6,456	6,597	6,597	5,989	5,989	21,440	19,464	1,976	19,284		
	May	18,262	18,262	15,686	15,686	92,040	79,057	12,983	5,406	5,586	5,586	5,130	5,130	18,155	16,673	1,480	14,465		
	June	15,258	15,258	12,682	12,682	76,900	63,917	12,983	5,196	5,661	5,661	5,205	5,205	18,398	16,916	1,482	14,465		
	July	15,102	15,102	12,526	12,621*	76,114	63,131	12,983	5,358	5,759	5,759	5,303	5,303	18,718	17,235	1,483	14,466		
	Aug.	15,263	15,263	12,687	12,687	76,926	63,942	12,984	5,442	5,757	5,757	5,301	5,301	18,710	17,228	1,482	14,466		
	Sept.	16,295	16,295	13,719	13,719	82,127	69,143	12,984	5,610	5,896	5,896	5,440	5,440	19,162	17,680	1,482	14,466		
	Oct.	18,138	18,138	14,704	14,704	91,416	74,108	17,308	5,712	6,291	6,291	5,683	5,683	20,446	18,470	1,976	19,284		
	Nov.	20,812	20,812	17,378	17,378	104,892	87,585	17,307	5,700	6,040	6,040	5,432	5,432	19,630	17,654	1,976	19,283		
	Dec.	26,163	26,163	22,729	22,729	131,861	114,554	17,307	6,342	6,597	6,597	5,989	5,989	21,440	19,464	1,976	19,283		
Total 1975						<u>\$1,194,580</u>	<u>\$1,008,511</u>	<u>\$186,069</u>						<u>\$237,667</u>	<u>\$215,429</u>	<u>\$21,243</u>	<u>\$207,312</u>		

EXHIBIT 2-JDOE LOAD CONTROL STUDY - NON GENERATING UTILITIESCase #2 - Winter Peaking Rural UtilityDEVELOPMENT OF ANNUAL EQUIVALENT OPERATION & MAINTENANCE EXPENSES

	OPERATION & MAINTENANCE EXPENSE FOR GENERIC TYPE (1)(2)					PRESENT WORTH FACTOR (3)	PRESENT WORTH FOR GENERIC TYPE (1)				
	I	II	III	IV	V		I	II	III	IV	V
1975	18,740	18,936	34,866	37,541	31,865	.952381	17,848	18,034	33,206	35,753	30,348
1976	20,052	20,262	37,307	40,169	34,096	.907029	18,188	18,378	33,839	36,434	30,926
1977	21,455	21,680	39,918	42,981	36,482	.863838	18,534	18,728	34,483	37,129	31,515
1978	22,957	23,197	42,712	45,989	39,036	.822702	18,887	19,084	35,139	37,835	32,115
1979	24,564	24,821	45,702	49,209	41,769	.783526	19,247	19,448	35,809	38,557	32,727
1980	26,284	26,559	48,901	52,653	44,692	.746215	19,614	19,819	36,491	39,290	33,350
1981	28,124	28,418	52,324	56,339	47,821	.710681	19,987	20,196	37,186	40,039	33,985
1982	30,092	30,407	55,987	60,283	51,168	.676839	20,367	20,581	37,894	40,802	34,632
1983	32,199	32,536	59,906	64,502	54,750	.644609	20,756	20,973	38,616	41,579	35,292
1984	34,453	34,813	64,100	69,018	58,583	.613913	21,151	21,372	39,352	42,371	35,965
1985	36,864	37,250	58,587	73,849	62,683	.584679	21,554	21,779	40,101	43,178	36,649
1986	39,445	39,857	73,388	39,018	67,071	.556837	21,964	22,194	40,865	44,000	37,348
1987	42,206	42,647	78,525	84,550	71,766	.530321	22,383	22,617	41,643	44,839	38,059
1988	45,160	45,633	84,022	90,468	76,790	.505068	22,809	23,048	42,437	45,692	38,784
1989	48,322	48,827	89,903	96,801	82,165	.481017	23,244	23,487	43,245	46,563	39,523
							306,533	309,738	570,306	614,061	521,218
						Annuity Factor - 5%/15 Yrs.	.096342	.096342	.096342	.096342	.096342
						Annual Equivalent	29,532	29,841	54,944	59,160	50,215

- NOTES: (1) Generic Types
 I - Radio
 II - Hybrid - Radio & Power Line Carrier
 III - Power Line Carrier (Low Frequency - Rhythm)
 IV - Power Line Carrier (Low Frequency - Multibit)
 V - Power Line Carrier (High Frequency)
 (2) O&M Expense escalated @ 7% per year
 (3) Discount Rate = 5%

EXHIBIT 2-KDOE LOAD CONTROL STUDY - NON GENERATING UTILITIESCase #2 - Winter Peaking Rural UtilityDEVELOPMENT OF ANNUAL EQUIVALENT CAPACITY COST SAVINGS

YEAR	CAPACITY COST SAVINGS		PRESENT WORTH	
	Calculated	Projected @ 7% Escalation	Factor (1)	Amount
1975	207,312		.952381	197,440
1976		221,824	.907029	201,201
1977		237,352	.863838	205,034
1978		253,966	.822702	208,938
1979		271,744	.783526	212,918
1980		290,766	.746215	216,974
1981		311,119	.710681	221,106
1982		332,898	.676839	225,318
1983		356,201	.644609	229,610
1984		381,135	.613913	233,984
1985		407,814	.584679	238,440
1986		436,361	.556837	242,982
1987		466,906	.530321	247,610
1988		499,590	.505068	252,327
1989		534,561	.481017	257,133
Total				3,391,015
Annuity Factor 5%/15 Yrs.				.096342
Annual Equivalent				326,697

NOTE: (1) Discount Rate = 5%

EXHIBIT 2-LDOE LOAD CONTROL STUDY - NON GENERATING UTILITIESCase #2 - Winter Peaking Rural UtilitySUMMARY OF BENEFIT/COST RATIOS AND PAYBACK PERIODSVarious Control Systems - Water Heater Control @ 100% Acceptance Rate

	RADIO	HYBRID RADIO & POWER LINE CARRIER	POWER LINE CARRIER		
			Low Frequency (Rhythm Keying)	Low Frequency (Multibit Code)	High Frequency (One Way)
<u>COST</u>					
Installed Cost	\$450,611	\$896,933	\$710,925	\$793,835	\$929,903
Fixed Charge Rate	10.43%	10.43%	10.43%	10.43%	10.43%
Annual Fixed Charges - Levelized	46,999	93,550	74,149	82,797	96,989
Operation & Maintenance Expenses (Annual Equivalent of Present Worth)	29,532	29,841	54,944	59,160	50,215
Total Annual Cost - Levelized	<u>\$ 76,531</u>	<u>\$123,391</u>	<u>\$129,093</u>	<u>\$141,957</u>	<u>\$147,204</u>
<u>BENEFIT</u>					
Annual Capacity Cost Savings by Reason of Water Heater Control - Levelized	<u>\$326,697</u>	<u>\$326,697</u>	<u>\$326,697</u>	<u>\$326,697</u>	<u>\$326,697</u>
<u>BENEFIT/COST RATIO</u>	<u>4.27</u>	<u>2.65</u>	<u>2.53</u>	<u>2.30</u>	<u>2.22</u>
<u>PAYBACK PERIOD</u>					
Cumulative Net Savings Exceed Installed Cost in Year	<u>2.3</u>	<u>4.4</u>	<u>3.8</u>	<u>4.3</u>	<u>4.4</u>

EXHIBIT 2-M

DOE LOAD CONTROL STUDY - NON GENERATING UTILITIES

Case #2 - Winter Peaking Rural Utility

DEVELOPMENT OF PAYBACK PERIODS

	YEAR	INSTALLED COST	CAPACITY COST SAVINGS	OPERATING EXPENSES			NET SAVINGS	
				O&M Expenses	Property Taxes	Total	For Year	Cumulative
I. RADIO		450,611						
	1		207,312	18,740	3,605	22,345	184,967	184,967
	2		221,824	20,052	3,605	23,657	198,167	383,134
	3		237,352	21,455	3,605	25,060	212,292	595,426
II. HYBRID		896,933						
	1		207,312	18,936	7,175	26,111	181,201	181,201
	2		221,824	20,262	7,175	27,437	194,387	375,588
	3		237,352	21,680	7,175	28,855	208,497	584,085
	4		253,966	23,197	7,175	30,372	223,594	807,679
	5		271,744	24,821	7,175	31,996	239,748	1,047,427
III. L.F. RHYTHM		710,925						
	1		207,312	34,866	5,687	40,553	166,759	166,759
	2		221,824	37,307	5,687	42,994	178,830	345,589
	3		237,352	39,918	5,687	45,605	191,747	537,336
	4		253,996	42,712	5,687	48,399	205,567	742,903
IV. L.F. MULTIBIT		793,835						
	1		207,312	37,541	6,351	43,892	163,420	163,420
	2		221,824	40,169	6,351	46,520	175,304	338,724
	3		237,352	42,981	6,351	49,332	188,020	526,744
	4		253,966	45,989	6,351	52,340	201,626	728,370
	5		271,744	49,209	6,351	55,560	216,184	944,554
V. H.F. One Way		929,903						
	1		207,312	31,865	7,439	39,304	268,008	268,008
	2		221,824	34,096	7,439	41,535	180,289	448,297
	3		237,352	36,482	7,439	43,921	193,431	641,728
	4		253,966	39,036	7,439	46,475	207,491	849,219
	5		271,744	41,769	7,439	49,208	222,536	1,071,755

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CASE #3SUMMER PEAKING - URBAN SYSTEM

Case #3 examines load control from the perspective of a municipal system in the south central section of the country. The service territory covers an area of relatively flat terrain approximately 13 by 14 miles. While the population is distributed throughout the entire region, a downtown center and associated high density residential area is located in the southeast and eastern extremities. The electrical network consists of ten transformer substations each of which feed's a radial type 12 KV distribution network. These medium voltage lines have facilities for interconnection between substations for switching purposes but line disconnects are normally operated in the open position at designated section points.

Feeds to the distribution substations are principally from an interconnected 69 KV transmission system (owned by the distribution authority) which has sources both from outside of the area and from a major 69/138 KV substation located close to the downtown area, the point of connection to the major generation source. A start in the upgrading of facilities has resulted in one distribution substation being converted to 138 KV operation with long range plans calling for a progressive conversion of the 69 KV facilities to 138 KV operation.

The system serves in excess of 14,000 residential customers and a large block of industrial load. Peak demands occur in late afternoon or early evening hours in July or August and reach as high as 144 MW. A survey of potentially controllable loads indicated a central air conditioning saturation of better than 30%. Because of the historical availability of relatively low cost natural gas in the area, the presence of electric water heaters is negligible. Consequently, load control

in this application will be directed toward minimizing demands imposed by the approximate 4,286 residential customers with central air conditioning.

Load Control Strategy

The simulation performed in this case to determine a load control strategy considered central air conditioner control only. The methodology is similar to the air conditioner portion of Case 4 that follows except for one important difference: the restore curves utilized for payback determination are based on test data collected by Arkansas Power and Light. The test was performed on only one home so that the results are statistically inconclusive. (For comparison the summer peaking rural case used Detroit Edison data.) The Arkansas tests show that if the central air conditioner is inhibited from being energized up to sixteen minutes an hour for four hours, it then takes the unit seven hours of continuous on-time after the control period to restore a 10° temperature reduction.

This utility had a peak summer day demand of 144 MW as shown in Exhibit 3-A. Since only one-fourth of the 4,286 air conditioners were controlled at any one time, the maximum controllable load became 4,616 KW: $(4,286 \times 4 \text{ KW} \times 1.0989 \times .98/4)$. This produced a control target of 139.4 MW.

Following the procedure established in the first case, a base load profile, i.e., the load curve with all air conditioning removed, was constructed as shown in Exhibit 3-D. The coincident demand data for air conditioners was taken from Georgia Power Company tests, illustrated in Exhibit 3-B. To utilize the above mentioned restore curves, the air conditioner loads were divided into eight equal groups with no group being controlled for more than fifteen minutes in any one

hour period. Keeping the same objectives (minimum off-time, equal control time) groups were inhibited and restored with the given coincident demand and restore constraints. The control target was never exceeded, but there does appear to have been a net KWH gain as Exhibit 3-D indicates. The long seven hour payback assumption is the direct cause.

The inhibit and restore schedules derived are listed in Exhibit 3-C. As the table illustrates, control was initiated at 3:00 PM when group #1 was inhibited to prevent exceeding the control target. Group 1's coincident demand at that time was 1,991 KW: $536 \text{ (air conditioners)} \times 3.45 \text{ KW (via Exhibit 3-B)} \times 1.0989 \times .98$. The arrow at 3:00 indicates the resultant amount of load shed. Groups were then cycled one at a time for 7.5 minutes until 3:45 at which time the load increased to the point where two groups had to be inhibited at once. Six cycles of groups inhibited in pairs followed, then at 6:52 the load dropped sufficiently to revert back to inhibiting one group at a time.

After all groups have been cycled twice, the assumption is made that the normal coincident demand schedule is not valid. The air conditioners will then maintain a full coincident demand of 4 KW. The resultant load curve is constructed by adding the load of 75% of all air conditioners running at 4 KW to the base line (no A/C) previously drawn. When only one group is being inhibited the demand increase is $7/8$ or 87.5%. At 6:52, 87% of the total A/C load or 16.1 MW is added to the base line to derive the resultant demand.

By 7:30 PM the system load profile has decreased sufficiently below the control target that all groups are restored (and running at 4 KW each). The seven hour restore assumption results in a KWH gain that extends past 2:00 AM (note the groups coming off in the control sequence at the bottom-right of Exhibit 3-D).

Exhibit 3-E summarizes the results of load control in this case showing the 'effect' on the system load profile, and the 'cause', i.e., the change in the central air conditioning load profile.

In summary, the load control strategy for Case 3, a summer peaking urban utility, consisted of controlling 4,286 central air conditioners in eight groups. The average group had air conditioners inhibited 8 times over a four hour period. The length of each inhibit was 7 1/2 minutes. The average time to restore the home to pre-control temperature was 7 hours. The load controlled represented a peak load shed of 3.2%.

Development of Control System Costs

In order to establish a basis for evaluation of alternative systems providing load control capability, each of five generic types were investigated. In each case, the specific physical requirements of the municipal electric system in question were controlling and the components incorporated in the pricing of each alternative load control system are designed to meet those requirements.

For each alternative, a common central control readout and logic for the determination of peak load conditions and initiation of load control action is assumed to be adequate as telemetered from the 69 KV injection point.

For illustrative purposes, all costs (and benefits) are developed on the basis of a 100% acceptance rate, i.e. agreement by all 4,286 air conditioning customers to accept such controls.

1. The Cost of Acquiring and Installing Control Apparatus

Installed system costs include both direct and indirect charges representing actual costs due vendors or other costs incurred by the utility in connection with the acquisition or installation of control facilities. Details supporting the development of overall installed costs for each of five generic types of control system are included in Exhibit 3-F. Each estimate uses as a basis the actual conditions prevailing at the location under study both in terms of system configuration and physical requirements. Pertinent features of alternative types of installation in the specific operating environment investigated are as follows:

- a. Radio - As previously indicated, the area to be covered is quite compact, consists of relatively flat terrain and is therefore quite

suited to radio control. The utility's experience with a presently installed two-way voice VHF radio system indicates that adequate coverage of the entire distribution area may be achieved with a single transmitter. Costs for a Radio Control System, detailed in Exhibit 3-F-I are predicated on the joint use of such common facilities as transmitter housing, power supply and antenna tower representing a significant cost savings. Total estimated costs for a Radio Control System are summarized below.

Radio Control System

Direct costs including spares	\$320,960
Indirect costs including contingencies	<u>77,121</u>
Total Installed Cost	<u>\$398,081</u>

- b. Hybrid: Radio and Power Line Carrier - The radio portion of this system carries with it the same cost savings recognized above. In addition, shared use of the VHF transformer appears feasible. As developed in Exhibit 3-F-II and summarized below, system costs clearly benefit from the urban character of the study area as reflected in the favorable ratio of controlled customers per transformer.

Hybrid Control System

Direct costs including spares	\$346,025
Indirect costs including contingencies	<u>119,732</u>
Total Installed Cost	<u>\$465,757</u>

- c. Low Frequency Power Line Carrier - As the system now exists, the application of a low frequency power line carrier is encouraged in that the system may be covered effectively by the use of a single

69 KV injection point. For estimating purposes, one additional medium voltage injection point was added to cover a small portion of the system not fed from the major 69 KV bus. Although this is a viable system, it must be recognized that the installation is vulnerable to system changes, changes which are already taking place. The section now requiring a separate medium voltage injection equipment has been recently converted from 69 KV to the new 138 KV level. Progress in this modification program could reduce the effectiveness of the 69 KV injection and involve additional 12 KV injection points or, alternatively, one 138 KV injection point. The additional costs of this latter solution (due to the higher voltage equipment and higher connected loads on the 138 KV system) could nullify the cost advantage now indicated.

The LF Power Line Carrier case is developed in both its simpler rhythm version and as a more complex multibit coded system. The multibit version would appear to have little justification other than for the additional versatility offered with respect to future control extensions. Costs associated with the respective Power Line Carrier scenarios are detailed in Exhibits 3-F-III and 3-F-IV and are summarized below.

	<u>LF POWER LINE CARRIER</u>	
	<u>Rhythm</u>	<u>Multibit</u>
Direct Costs including spares	\$465,035	\$733,664
Indirect Costs including contingencies	151,168	155,928
Total Installed Cost	<u>\$616,203</u>	<u>\$889,592</u>

- d. High Frequency Power Line Carrier - The somewhat limited range of the high frequency system suggested a conservative approach in the application of sector injection units for an area where the total number of controlled customers is a relatively small proportion of the total system (approximately 1 in 3). It was assumed that the controlled customers were evenly distributed throughout the system, an action which dictated the use of a low loading factor on the line type units (approximately 24%) but one which roughly equaled the costs of an equivalent number of substation installed units and gave a not overly optimistic view of probable costs. To be comparable with the remaining studies, connections of the injection units to the control center is by means of individual leased telephone lines although, as noted before, shared use of these lines by several injection units is probably more realistic.

Costs for the high frequency system are developed in Exhibit 3-F-V and are summarized below. It should be noted that although the high frequency system lends itself to two way communication and the ancillary functions associated therewith, only the single function of load control is treated in this analysis.

High Frequency Power Line Carrier (One Way)

Direct Costs including spares	\$671,753
Indirect costs including contingencies	137,211
Total Installed Cost	<u>\$808,964</u>

2. Operation and Maintenance Expense

Because of the relatively few points under control, it is not anticipated that any Company personnel need be exclusively dedicated to the operation of any of the control systems. By their nature, operation costs would consist primarily of charges for leased telephone lines or those associated with a microwave channel as applicable for the respective systems. Anticipated maintenance costs consist primarily of personnel charges and consumable spares. Average annual O&M Expense estimates for each generic control system type are developed in Exhibit 3-G and are summarized as follows:

<u>Control System</u>	<u>Estimated Average Annual Operation & Maintenance Expense</u>
I. Radio	\$12,948
II. Hybrid	\$12,782
III. LF Power Line Carrier - Rhythm	\$25,596
IV. LF Power Line Carrier - Multibit	\$28,757
V. HF Power Line Carrier	\$31,499

Development of Estimated Capacity Cost Savings

Since, by definition, each of the utilities considered in this analysis is non-generating, that is, dependent upon external sources for power supply, it is evident that the overwhelming benefit of load control will be reflected in reduced capacity charges for purchased power.

Based on tests by other utilities with similar weather conditions, a diversified demand of 4 KW per central air conditioner is considered representative. However, under the load control strategy formulated for this application only one out of four air conditioners would be deenergized at any given time. Consequently, a controlled demand of 1 KW per air conditioner is assumed.

In order to extrapolate control point demands to the point of wholesale delivery to the system, distribution losses must be recognized. For purposes of this analysis, system losses under peak conditions are assumed at approximately 9% of delivered kilowatts. Finally, it must be anticipated that some portion of control apparatus may not be operational at any given time. In recognition of this factor, a 2% failure rate is incorporated in the development of total potentially controllable air conditioning loads. This determination may then be expressed as:

$$C = \frac{ND(1-F)}{1-L}$$

When:

C = Controlled Air Conditioning Load
 N = Number of Controlled Air Conditioners
 D = Diversified Demand per Air Conditioner
 F = Failure Rate
 L = System Losses

Substituting values as indicated above, potentially controllable air conditioner demand is established as:

$$C = \frac{(4,286)(1KW)(1-.02)}{(1-.09)} = \underline{\underline{4,616 \text{ KW}}}$$

The wholesale rate under which the utility purchases power provides for capacity charges at a fixed \$2.50 per KW. In the area served, summer conditions prevail for about five months out of the year and the reduction of monthly peak due to control of air conditioners would be effective only during that period. Even then, full benefit of load control may not be realized because of the 80% demand ratchet imposed by the supplier's wholesale rate.

Each of these factors are considered in the detailed calculation of capacity cost savings developed in Exhibit 3-H which serves as the basis for load control benefits evaluated in the analysis which follows.

Evaluation of Load Control Costs and Benefits

The methodology proposed for cost/benefit analysis is predicated on a consideration of relative annual or annual equivalent costs and/or benefits as levelized. A further basic consideration of the proposed methodology is that it takes its perspective from the viewpoint of the ultimate consumer's revenue requirements.

Accordingly, control systems are translated into annual fixed charges representing levelized costs to the ratepayer in the form of debt service. The municipal system is not subject to property or income taxes.

Fixed Charge Rate

The utility serving as the model for the summer peaking urban model is a municipal system. Consequently, the cost of money component of the fixed charge rate may be considered that for municipal bonds. In the time frame of the analysis, an interest rate of 7% is considered appropriate for municipal debt issues.

Depreciation in the context of a fixed charge rate is established as the sinking fund charge indicated at an interest (discount) rate equal to the cost of money over the estimated service life of the investment. This may be expressed by the following formula:

$$D = \frac{(1-s)i}{(1+i)^n - 1}$$

Where: i = interest (discount) rate
 n = service life
 s = salvage value

Then, for a discount rate equal to the cost of money (7.00%) from above, and service life estimated at 15 years and zero salvage:

$$D = \frac{.07}{(1.07)^{15} - 1} = \frac{.07}{1.7590} = .0398 \text{ or } \underline{\underline{3.98\%}}$$

The cost of money and sinking fund depreciation together constitute the capital recovery factor which in this application represents the total fixed charge rate.

In summary, the Fixed Charge Rate developed for application in Case #3 is then:

Case #3 Fixed Charge Rate

Cost of Money	7.00%
Depreciation	3.98
Fixed Charge Rate	<u>10.98%</u>

Development of Levelized Annual Fixed Charges

Levelized annual fixed charges for each generic type of control system are developed as the product of individual Installed Cost estimates and the Fixed Charge Rate as developed above:

	GENERIC TYPE				
	I (Radio)	II (Hybrid)	III (LF-Rhythm)	IV (LF-Multibit)	V (HF-OneWay)
Installed Cost	\$398,081	\$465,757	\$616,203	\$889,592	\$808,964
Fixed Charge Rate	10.98%	10.98%	10.98%	10.98%	10.98%
Annual Fixed Charges - Levelized	\$ 43,709	\$ 51,140	\$ 67,659	\$ 97,677	\$ 88,824

It should be noted that for this illustrative case, we have assumed a 15 year life and zero salvage value for each generic type. Any variation in either factor would obviously result in a different Fixed Charge Rate. The purpose of the methodology proposed is, in fact, to provide a valid basis for comparison when such differences exist as between generic types.

Development of Levelized Annual O&M Expense

Current (1975) levels of operation and maintenance expense estimates have been developed above for each generic type control system. It is likely, however, that, because of wage and other price adjustments, the level of annual O&M expense will escalate over the life cycle assumed for each control system. For purposes of this

analysis, we have assumed escalation at an estimated level of 7% per annum through 1989, the fifteenth year of operation.

Under the proposed Cost/Benefit methodology, O&M expense is developed as the annual equivalent of the present worth of alternative expense streams. Again, since in the instant case the same service life (15 years) is assumed for each system, the necessity for this treatment is not as apparent. However, for illustrative purposes, the procedure has been carried out in Exhibit 3-J. The Present Worth Factor for each year as applied to yearly expense in order to develop present worth is the result of the following formula:

$$FWF_n = \frac{1}{(1+i)^n}$$

Where:

FWF_n = Present Worth Factor for Year n
 i = Discount Rate (In this Case 7.00%)
 n = year

Then:

$$PW = \sum_{n=1}^{15} \frac{E_n}{(1+i)^n} \quad \text{where } E = \text{yearly expense}$$

Note that in this application, the present worth of escalated annual O&M expense results in a fixed annual amount for each alternative system. This is the obvious result of the fact that the escalation rate and the discount rate are the same (7%). We have, however, carried the calculation out to conclusion for illustrative purposes.

Total Present Worth for each O&M Expense stream is further shown in Exhibit 3-B. In order to express the respective amounts in terms of annual equivalents, an annuity factor is applied. The annuity factor results from the following formula:

$$AF = \frac{i(1+i)^n}{(1+i)^n - 1} = \underline{\underline{.109795}}, \text{ where } i = .07 \text{ and } n = 15$$

On an annual equivalent basis, the O&M Expense component for each generic system is then:

	GENERIC TYPE				
	I	II	III	IV	V
Present Worth of Annual Expense	\$181,515	\$179,190	\$358,815	\$403,140	\$441,570
Annuity Factor	.109795	.109795	.109795	.109795	.109795
Annual Equivalent	<u>\$ 19,929</u>	<u>\$ 19,674</u>	<u>\$ 39,396</u>	<u>\$ 44,263</u>	<u>\$ 48,482</u>

Development of Levelized Capacity Cost Savings

For purposes of this analysis, load control system benefits are equated to savings in the capacity cost component of purchased power. The determination of current savings levels has been previously discussed and is detailed in Exhibit 3-H. As with other operating expenses, it is reasonable to assume that purchased power expense; and hence, capacity cost levels would continue to escalate in the future.

Recognizing this factor and applying the same technique previously described for O&M Expenses, the annual equivalent of the present worth of future capacity cost savings is developed as shown in Exhibit 3-K. Levelized annual capacity cost savings are calculated at \$172,982.

Summary of Costs and Benefits and Development of Benefit/Cost Ratio and Payback Periods

Exhibit 3-L summarizes levelized annual costs and capacity cost savings for each load control system type analyzed.

The Benefit/Cost Ratio is favorable in each instance as further demonstrated in Exhibit 3-L and summarized below:

	GENERIC TYPE				
	I	II	III	IV	V
Benefit/Cost Ratio	<u>2.72</u>	<u>2.44</u>	<u>1.62</u>	<u>1.22</u>	<u>1.26</u>

As a further measure of project viability, the Payback Period defined as the period necessary to recoup project costs through accumulated net savings, is developed for each system analyzed in Exhibit 3-M, and are summarized in Exhibit 3-L.

Sensitivity Analyses

The Benefit/Cost Ratios developed above are predicated, among other things, upon

1. 100% Acceptance Rate by Water Heater Customers
2. Escalation of future Capacity Cost Savings @ 7% p a

Obviously, actual circumstances could depart from these assumptions underlying this analysis.

In order to measure the impact of variations in either of these analysis components, Exhibit 3-N has been prepared to demonstrate levelized costs and benefits at acceptance rates varying from 0 to 100%. For this purpose, Load Control System costs were separated between fixed (central facilities, etc.) and variable (receivers, unit installation, etc.) components with the fixed portion applying even at 0% acceptance and variable costs incrementing with additional connections. It should be noted that this graph was prepared on the basis of specific data for the case under analysis and should not be construed as being a general representation.

Exhibit 3-N also depicts capacity cost savings at various acceptance levels without escalation. It may be seen that even on this basis, System IV and System V costs exceed benefits even at 100% acceptance. Favorable Benefit/Cost ratios would result for all other systems with acceptance rates in excess of approximately 55%. With escalation, capacity cost savings exceed costs for all Systems at acceptance levels varying from 5% to 65%.

Customer Incentives

On a break-even basis, monthly customer incentive could be offered at a maximum level represented by the following:

$$CI = \frac{.0833 (B_1 - C_1)}{N}$$

Where:

CI = Customer Incentive
 B₁ = Annual Equivalent Benefit for Generic Type 1
 C₁ = Annual Equivalent Cost for Generic Type 1
 N = Number of Water Heater Customers Accepting Control

From data developed above, maximum monthly customer incentive for the radio control system at the 100% acceptance rate would then be:

$$CI = \frac{.0833(172,982-63,638)}{4,286} = \frac{9,108}{4,286} = \underline{\underline{\$2.13 \text{ per month}}}$$

Obviously, for customer acceptance at a lower level, benefits, costs and the number of customers would have to be adjusted accordingly. A graph similar to Exhibit 3-N would be useful in this respect.

EXHIBIT 3A
CASE STUDY 3
SUMMER PEAKING URBAN UTILITY
SYSTEM PEAK DAY LOAD PROFILE

EXHIBIT 3B
CASE STUDY 3
TYPICAL SUMMER LOAD PROFILE
CENTRAL AIR CONDITIONERS

EXHIBIT 3-CSUMMER PEAKING URBAN UTILITY - CONTROL SEQUENCE AT PEAK DAY

GIVEN: System Peak: 144 MW at 5 PM
 Controllable Load: 4.6 MW
 Control Target: 139.4 MW
 Group Size: 536

INHIBIT SEQUENCE

<u>TIME OF INHIBIT</u>	<u>MINIMUM DEMAND REDUCTION NEEDED IN NEXT 7.5 MINUTES</u>	<u>GROUP DEMAND AT TIME OF INHIBIT</u>	<u>NUMBER GROUPS INHIBITED</u>	<u>TOTAL LOAD SHED</u>	<u>RESULTANT DEMAND (MW)</u>
3:00	500 KW	536 x LF x .98 x 3.45 = 1991	1	1991	137.7
3:07.5	1000	536 x LF x .98 x 3.47 = 2003	1	2003	138.0
3:15	1300	536 x LF x .98 x 3.50 = 2020	1	2020	138.2
3:22.5	1800	536 x LF x .98 x 3.51 = 2027	1	2027	139.4
3:30	2000	536 x LF x .98 x 3.52 = 2032	1	2032	139.4
3:37.5	2600	536 x LF x .98 x 3.54 = 2043	1	2043	139.4
3:45	2900	536 x LF x .98 x 3.58 = 2066	2	4132	139.4
3:52.5	3200	536 x LF x .98 x 3.60 = 2068	2	4136	139.4
4:00	3400	536 x LF x .98 x 3.65 = 2078	2	4156	139.4
4:07.5	3700	536 x LF x .98 x 3.67 = 2118	2	4237	139.4
4:15	3900	536 x LF x .98 x 3.70 = 2135	2	4271	139.4

All groups through two cycles of inhibit. Groups controlled in pairs until 6:52. At this time load profile has dropped sufficiently to allow single group inhibits. Last inhibit is removed at 7:30 PM.

RESTORE SEQUENCE

The restore sequence in air conditioning control occurs when the inhibits are removed. Therefore the 'restore sequence' is incorporated above from 6:52.5 to 7:30 PM. The assumption is that after two cycles of control, units are running at maximum coincident demand or 4 KW. Recall, however, that two groups out of eight are controlled for six out of the eight cycles. This means that system load is derived by adding the following factor to the "Load Curve with A/C Removed" from 3:45 to 6:52.5: 4286 (A/C's) x 4 KW x 1.0989 x .98 x .75 or 13.8 MW. During the last cycle when only one group is controlled this factor increases to 16.1 MW.

EXHIBIT 3E

CASE STUDY 3
SUMMER PEAKING URBAN

AIR CONDITIONER CONTROL - EFFECT ON SYSTEM LOAD PROFILE

EXHIBIT 3-F-I

DOE LOAD CONTROL STUDY - NON GENERATING UTILITIESCase #3 - Summer Peaking Urban UtilityDEVELOPMENT OF INSTALLED COSTS - VARIOUS GENERIC SYSTEMSSystem I - Radio

	<u>Amount Paid to Vendor</u>	<u>All Other Costs to the Utility</u>	<u>Total Cost</u>
<u>Direct Cost</u>			
4,286 receivers @ \$70	\$ 300,020		
1 transmitter and antenna @ \$7,000	7,000		
1 antenna tower - joint use	-		
1 transmitter land line - joint use	-		
1 bulk supply paint metering @ 2,500	2,500		
1x2 circuit leased line (4 circuit miles @ \$60/circuit		\$ 120	
1 control center	<u>4,000</u>		
	\$ 313,520	\$ 120	\$ 313,640
Spares - 1 year operation			
86 - (2%) of receivers	\$ 6,020		
1 lot - transmitter spares	700		
1 lot - telemetering and control	<u>600</u>		
Total Spares	\$ 7,320		\$ 7,320
<u>Indirect Costs</u>			
Installation of 4,286 receivers @ \$15		\$ 64,290	
Installation of transmitter @ 50 MH		900	
Installation of control and telemetering @ 40 MH		720	
Initial test @ 64 MH		1,152	
Contingency 15%		<u>10,059</u>	
		\$ 77,121	\$ 77,121
Total			<u>\$ 398,081</u>

Average cost/customer \$92.88

EXHIBIT 3-F-II

DOE LOAD CONTROL STUDY - NON GENERATING UTILITIESCase #3 - Summer Peaking Urban UtilityDEVELOPMENT OF INSTALLED COSTS - VARIOUS GENERIC SYSTEMSSystem II - Hybrid: Radio and Power Line Carrier

	<u>Amount Paid to Vendor</u>	<u>All Other Costs to the Utility</u>	<u>Total Cost</u>
<u>Direct Customers</u>			
4,286 end use receivers @ \$45 (A/C)	\$ 192,870		
1,225 VHF receivers @ \$110	134,750		
1 - transmitter complete - joint use	-		
1 - microwave transmitter link - joint use	-		
1 - master controller	6,000		
1 - bulk supply point metering	2,500		
1x2 circuit leased line (4 circuit miles) @ \$60 per circuit		\$ 120	
1 - control center	<u>4,500</u>		
	\$ 340,620	\$ 120	\$ 340,740
Spares - 1 year operation			
43 - (1%) end use receivers	\$ 1,935		
25 - 2% VHF receivers	2,750		
1 lot - telemetering and control	<u>600</u>		
	\$ 5,285		\$ 5,285
<u>Indirect Costs</u>			
Installation of 4,286 end use receivers \$15		\$ 64,290	
Installation of 1,225 VHF receivers @ 1.5 MH		33,075	
Installation of control and telemetering 60 MH		1,080	
Initial test 2,103 x 0.15 = 31.5 MH		5,670	
Contingency 15%		<u>15,617</u>	
		\$119,732	\$ 119,732
Total			<u>\$ 465,757</u>

Average cost/customer = \$84.51

EXHIBIT 3-F-III

DOE LOAD CONTROL STUDY - NON GENERATING UTILITIESCase #3 - Summer Peaking Urban UtilityDEVELOPMENT OF INSTALLED COSTS - VARIOUS GENERIC SYSTEMSSystem III - LF Power Line Carrier, Rhythm Keying

	<u>Amount Paid to Vendor</u>	<u>All Other Costs to the Utility</u>	<u>Total Cost</u>
<u>Direct Cost</u>			
4,286 receivers @ \$55	\$ 235,730		
1 - 69 kV injection equipment ≈ 200 kW audio	69,000		
1 - 69 kV substation switchgear bay		\$ 75,000	
1 - 12 kV injection equipment ≈ 30 kW audio	45,000		
1 - 12 kV bus connection and feeder		2,500	
1 - bulk supply point metering (2x1)+(1x2) circuit leased line (8 circuit miles) @ \$60/circuit	2,500		
1 - control center	7,000		
	<u>\$ 359,230</u>	<u>\$ 77,740</u>	<u>\$ 436,970</u>
 Spares - 1 year operations			
43 - (1%) receivers	\$ 2,365		
1 lot - injection equipment spares	25,000		
1 lot - telemetering and control	700		
	<u>\$ 28,065</u>		<u>\$ 28,065</u>
 <u>Indirect Costs</u>			
Installation of 4,286 receivers @ \$15		\$ 64,290	
Installation of 69 kV injection, 320 MH + \$50,000		55,760	
Installation of 12 kV injection, 240 MH + \$1,500		5,820	
Installation of control and telemetering 60 MH		1,080	
Initial tests - 250 MH		4,500	
Contingency 15%		19,718	
		<u>\$151,168</u>	<u>\$ 151,168</u>
 Total			<u><u>\$ 616,203</u></u>

Averages cost/customer \$143.77

EXHIBIT 3-F-IV

DOE LOAD CONTROL STUDY - NON GENERATING UTILITIESCase #3 - Summer Peaking Urban UtilityDEVELOPMENT OF INSTALLED COSTS - VARIOUS GENERIC SYSTEMSSystem IV - LF Power Line Carrier, Multibit Code

	<u>Amount Paid to Vendor</u>	<u>All Other Costs to the Utility</u>	<u>Total Cost</u>
<u>Direct Cost</u>			
4,286 receivers @ \$76	\$ 325,736		
1 - 69 kV injection equipment @ \$1200/MVA*	240,000		
1 - 69 kV substation switchgear		\$ 75,000	
1 - 12 kV injection equipment	40,000		
1 - 12 kV bus connection and feeder		2,500	
1 bulk supply point metering (2x1)+(1x2) circuit leased line (8 circuit miles) @ \$60/circuit	2,500		
		240	
1 - control center	<u>11,720</u>		
	\$ 619,956	\$ 77,740	\$ 697,696
Spares - 1 year operation			
43 - (1%) receivers	\$ 3,268		
1 lot injection equipment spares	32,000		
1 lot telemetering and control	<u>700</u>		
	\$ 35,968		\$ 35,968
<u>Indirect Costs</u>			
Installation of 4,286 receivers @ \$15		\$ 64,290	
Installation of 69 kV injection 320 MH + \$50,000		55,760	
Installation of 12 kV injection 240 MH + \$1,500		5,820	
Installation of control and telemetering 60 MH		1,080	
Initial tests 480 MH		8,640	
Contingency 15%		<u>20,338</u>	
		\$ 155,928	\$ 155,928
Total			<u>\$ 889,592</u>
Average cost/customer	\$207.56		

* 200 MVA.

EXHIBIT 3-F-VDOE LOAD CONTROL STUDY - NON GENERATING UTILITIESCase #3 - Summer Peaking Urban UtilityDEVELOPMENT OF INSTALLED COSTS - VARIOUS GENERIC SYSTEMSSystem V - High Frequency Power Line Carrier

	<u>Amount Paid to Vendors</u>	<u>All Other Costs to the Utility</u>	<u>Total Cost</u>
<u>Direct Cost</u>			
4,286 end use receivers @ \$95	\$ 407,170		
17 sector injection units @ \$9,700	164,900		
17 sets 12 KV connection equipment @ \$500 (17x1) + (1x2) circuit leased line		\$ 8,500	
(76 circuit miles) @ \$60/circuit		1,140	
1 set bulk supply point metering	2,500		
1 control center	50,000		
	<u>\$ 624,570</u>	<u>\$ 9,640</u>	<u>\$ 634,310</u>
Spares - 1 year operation			
86 - (2%) end use receivers	\$ 8,143		
2 - sector injection units	19,400		
1 lot - telemeter and control	10,000		
	<u>\$ 37,543</u>		<u>\$ 37,543</u>
<u>Indirect Costs</u>			
Installation of 4,286 end use receivers @ \$8		\$ 34,288	
Installation of 4,286 low voltage connections @ \$15		64,290	
Installation of 17 sector injection units @ 16 MH		4,896	
Installation of control and telemetering @ 320 MH		5,760	
Initial test 560 MH		10,080	
Contingency 15%		17,897	
		<u>\$137,211</u>	<u>\$ 137,211</u>
Total			<u>\$ 808,964</u>

Average cost/customer \$188.75

EXHIBIT 3-GDOE LOAD CONTROL STUDY - NON GENERATING UTILITIESCase #3 - Summer Peaking Urban UtilityDEVELOPMENT OF COSTS - VARIOUS GENERIC SYSTEMSV - Estimated Operation & Maintenance Expense

Page 1 of 2

	<u>MANHOURS</u>	<u>EXPENSE</u>
I. <u>RADIO</u>		
<u>Maintenance Labor</u>		
Xmitter - 0.5 day/month x 2 men	96	
Receivers - 86/year @ 1 MH each	86	
Complaints - 10/month @ 3 MH each	360	
Control - 0.5 MH/month	6	
Total	548 @ \$18	\$ 9,864
Leased Lines - 4 circuit miles		
@ 3.25/mile/month		156
Consumable Spares - 7,320 x 0.4		2,928
Total		\$12,948
II. <u>HYBRID</u>		
<u>Maintenance Labor</u>		
Xmitter (part of 2 way voice system)	0	
Receivers VHF-25/year @ 7 MH each	175	
Complaints - 10/month @ 3 MH each	360	
Control - 0.5 MH/month	6	
Receivers, End Use - 43 @ 1 MH each	43	
Total	584 @ \$18	\$10,512
Leased Lines - 4 circuit miles		
@ 3.25/mile/month		156
Consumable Spares - 5,285 x 0.4		2,114
Total		\$12,782
III. <u>PLC - LF RHYTHM</u>		
<u>Maintenance Labor</u>		
Receivers - 43/year @ 1 MH each	43	
Injection Points - Inspect 2 @ 8 MH/		
month	192	
Complaints - 15/month @ 3 MH each	540	
Control - 0.5 MH/month	6	
Total	781 @ \$18	\$14,058
Leased Lines - 8 circuit miles		
@ 3.25/mile/month		312
Subtotal		14,370
Consumable Spares - 28,065 x 0.4		11,226
Total		\$25,596
IV. <u>PLC - MULTIBIT CODE</u>		
Subtotal from above		\$14,370
Consumable Spares - 35,968 x 0.4		14,387
Total		\$28,757

EXHIBIT 3-GDOE LOAD CONTROL STUDY - NON GENERATING UTILITIESCase #3 - Summer Peaking Urban UtilityDEVELOPMENT OF COSTS - VARIOUS GENERIC SYSTEMSV - Estimated Operation & Maintenance Expense

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	<u>MANHOURS</u>	<u>EXPENSE</u>
V. <u>PLC HIGH FREQUENCY (One Way)</u>		
<u>Maintenance Labor</u>		
Receivers - 86/year @ 1.5 MH each	129	
Injection points - inspect 17 @ 2 MH/point	34	
Injection unit - repair/replace 2/yr. @ 12 MH	24	
Complaints - 15/month @ 3 MH each	540	
Control - 2 MH per month	24	
Total	751 @ \$18	\$13,518
Leased Lines - 76 circuit miles @ \$3.25/m/mth		2,964
Consumable spares - 37,543 x 0.4		15,017
Total		<u>\$31,499</u>

EXHIBIT 3-HDOE LOAD CONTROL STUDY - NON-GENERATING UTILITIESCase #3 - Summer Peaking Urban UtilityDEVELOPMENT OF CAPACITY COST SAVINGS WITH LOAD CONTROLPurchased Power Costs Adjusted for 100% Central Air Conditioner Control

		80% RATCHET						
		KW Demand, No Control		KW Demand, With Control ⁽¹⁾		Demand Charges @\$2.50/KW		INDICATED SAVINGS
		Actual	Billing	Actual	Billing	No Control	With Control	
1974	11 Mo. Peak @ 80%		107,302		107,302			
1975	January	100,173	107,302*	100,173	107,302*	\$ 268,255	\$ 268,255	
	February	94,622	107,302*	94,622	107,302*	268,255	268,255	
	March	86,908	107,302*	86,908	107,302*	268,255	268,255	
	April	92,279	107,302*	92,279	107,302*	268,255	268,255	
	May	116,827	116,827	112,211	112,211	292,068	280,528	\$ 11,540
	June	130,020	130,020	125,404	125,404	325,050	313,510	11,540
	July	143,898	143,898	139,282	139,282	359,745	348,205	11,540
	August	144,186	144,186	139,570	139,570	360,465	348,925	11,540
	September	142,996	142,996	138,380	138,380	357,490	345,950	11,540
	October	105,040	115,348*	105,040	111,656*	288,370	279,140	9,230
	November	92,027	115,348*	92,027	111,656*	288,370	279,140	9,230
	December	97,326	115,348*	97,326	111,656*	288,370	279,140	9,230
	Total 1975					<u>\$3,632,948</u>	<u>\$3,547,558</u>	<u>\$ 85,390</u>
1975	11 Mo. Peak @ 80%		115,348		111,656			
1976	January	107,686	115,348*	107,686	111,656*	\$ 288,370	\$ 279,140	\$ 9,230
	February	101,719	115,348*	101,719	111,656*	288,370	279,140	9,230
	March	93,426	115,348*	93,426	111,656*	288,370	276,140	9,230
	April	99,200	115,348*	99,200	111,656*	288,370	279,140	9,230
	May	125,589	125,589	120,973	120,973	313,973	302,433	11,540
	June	139,771	139,771	135,155	135,155	349,428	337,888	11,540
	July	154,690	154,690	150,074	150,074	386,725	375,185	11,540
	August	155,000	155,000	150,384	150,384	387,500	375,960	11,540
	September	153,721	153,721	149,105	149,105	384,303	372,763	11,540
	October	112,918	124,000*	112,918	120,307*	310,000	300,768	9,232
	November	98,929	124,000*	98,929	120,307*	310,000	300,768	9,232
	December	104,625	124,000*	104,625	120,307*	310,000	300,768	9,232
	Total 1976					<u>\$3,905,409</u>	<u>\$3,783,093</u>	<u>\$122,316</u>

* Ratchet Imposed

(1) 4,286 central air conditioners controlled @ 10 KW; 2% failure rate; 9% system losses:
 $(4,286 \times 1.0 \times 1/.91) \times .98 = 4,616 \text{ KW}$

EXHIBIT 3-J

DOE LOAD CONTROL STUDY - NON GENERATING UTILITIES

Case #3 - Summer Peaking Urban Utility

DEVELOPMENT OF ANNUAL EQUIVALENT OPERATION & MAINTENANCE EXPENSES

	OPERATION AND MAINTENANCE EXPENSE FOR GENERIC TYPE (1) (2)					PRESENT WORTH FACTOR (3)	PRESENT WORTH FOR GENERIC TYPE				
	I	II	III	IV	V		I	II	III	IV	V
1975	12,948	12,782	25,595	28,757	31,499	.934579	12,101	11,946	23,921	26,876	29,438
1976	13,854	13,677	27,387	30,770	33,704	.873439	12,101	11,946	23,921	26,876	29,438
1977	14,824	14,634	29,304	32,924	36,063	.816298	12,101	11,946	23,921	26,876	29,438
1978	15,862	15,658	31,355	35,229	38,588	.762895	12,101	11,946	23,921	26,876	29,438
1979	16,972	16,755	33,550	37,695	41,289	.712986	12,101	11,946	23,921	26,876	29,438
1980	18,160	17,927	35,898	40,333	44,179	.666342	12,101	11,946	23,921	26,876	29,438
1981	19,431	19,182	38,411	43,157	47,272	.622750	12,101	11,946	23,921	26,876	29,438
1982	20,792	20,525	41,100	46,177	50,581	.582009	12,101	11,946	23,921	26,876	29,438
1983	22,247	21,962	43,977	49,410	54,121	.543934	12,101	11,946	23,921	26,876	29,438
1984	23,804	23,499	47,055	52,869	57,910	.508349	12,101	11,946	23,921	26,876	29,438
1985	25,471	25,144	50,349	56,569	61,963	.475093	12,101	11,946	23,921	26,876	29,438
1986	27,254	26,904	53,874	60,529	66,301	.444012	12,101	11,946	23,921	26,876	29,438
1987	29,161	28,788	57,645	64,766	70,942	.414964	12,101	11,946	23,921	26,876	29,438
1988	31,203	30,803	61,680	69,300	75,908	.387817	12,101	11,946	23,921	26,876	29,438
1989	33,387	32,959	65,998	74,151	81,221	.362446	12,101	11,946	23,921	26,876	29,438
Total							181,515	179,190	358,815	403,140	441,570
						Annuity Factor 7%/15 Yrs.	.109795	.109795	.109795	.109795	.109795
						Annual Equivalent	19,929	19,674	39,396	44,263	48,482

EXHIBIT 3-KDOE LOAD CONTROL STUDY - NON GENERATING UTILITIESCase #3 - Summer Peaking Urban UtilityDEVELOPMENT OF ANNUAL EQUIVALENT CAPACITY COST SAVINGS

	<u>CAPACITY COST SAVINGS</u>		<u>PRESENT WORTH</u>	
	<u>Calculated</u>	<u>Projected @ 7% Escalation</u>	<u>Factor (1)</u>	<u>Amount</u>
1975	85,390		.934579	79,804
1976	122,316		.873439	106,836
1977		130,878	.816298	106,835
1978		140,040	.762895	106,836
1979		149,842	.712986	106,835
1980		160,331	.666342	106,835
1981		171,555	.622750	106,836
1982		183,563	.582009	106,835
1983		196,413	.543934	106,836
1984		210,162	.508349	106,836
1985		224,873	.475093	106,836
1986		240,614	.444012	106,836
1987		257,457	.414964	106,835
1988		275,479	.387817	106,835
1989		294,763	.362446	106,836
Total				1,575,502
		Annuity Factor 7%/15 Yrs.		.109795
		Annual Equivalent		172,982

NOTE: (1) Discount Rate = 7%

EXHIBIT 3-L

DCE LOAD CONTROL STUDY - NON GENERATING UTILITIES

Case #3 - Summer Peaking Urban Utility

SUMMARY OF BENEFIT/COST RATIOS AND PAYBACK PERIODS

Various Control Systems - Water Heater Control @ 100% Acceptance Rate

	RADIO	HYBRID RADIO & POWER LINE CARRIER	POWER LINE CARRIER		
			Low Frequency (Rhythm Keying)	Low Frequency (Multibit Code)	High Frequency (One Way)
<u>COST</u>					
Installed Cost	\$398,081	\$457,757	\$616,203	\$889,592	\$808,964
Fixed Charge Rate	10.98%	10.98%	10.98%	10.98%	10.98%
Annual Fixed Charges - Levelized	43,709	51,140	67,659	97,677	88,824
Operation & Maintenance Expenses (Annual Equivalent of Present Worth)	19,929	19,674	39,396	44,263	48,482
Total Annual Cost - Levelized	<u>\$ 63,638</u>	<u>\$ 70,814</u>	<u>\$107,055</u>	<u>\$141,940</u>	<u>\$137,306</u>
<u>BENEFIT</u>					
Annual Capacity Cost Savings by Reason of Air Conditioner Control - Levelized	<u>\$172,982</u>	<u>\$172,982</u>	<u>\$172,982</u>	<u>\$172,982</u>	<u>\$172,982</u>
<u>BENEFIT/COST RATIO</u>	<u>2.72</u>	<u>2.44</u>	<u>1.62</u>	<u>1.22</u>	<u>1.26</u>
<u>PAYBACK PERIOD</u>					
Cumulative Net Savings Exceed Installed Cost in Year	<u>3.8</u>	<u>4.3</u>	<u>6.1</u>	<u>8.3</u>	<u>7.9</u>

EXHIBIT 3-MDOE LOAD CONTROL STUDY - NON GENERATING UTILITIESCase #3 - Summer Peaking Urban UtilityDEVELOPMENT OF PAYBACK PERIODS

	YEAR	INSTALLED COST	CAPACITY COST SAVINGS	O&M EXPENSES	NET SAVINGS	
					For Year	Cumulative
I. RADIO		398,081				
	1		85,390	12,948	72,442	72,442
	2		122,316	13,854	108,462	180,904
	3		130,878	14,824	116,054	296,958
	4		140,040	15,862	124,178	421,136
II. HYBRID		465,757				
	1		85,390	12,782	72,608	72,608
	2		122,316	13,677	108,639	181,247
	3		130,878	14,634	116,244	297,491
	4		140,040	15,658	124,382	421,873
	5		149,842	16,755	133,087	554,960
III. L.F. - RHYTHM		616,203				
	1		85,390	25,595	59,795	59,795
	2		122,316	27,387	94,929	154,724
	3		130,878	29,304	101,574	256,298
	4		140,040	31,355	108,685	364,983
	5		149,842	33,550	116,292	481,275
	6		160,331	35,898	124,433	605,708
	7		171,555	38,411	133,144	738,852
IV. L.F. - MULTIBIT		889,592				
	1		85,390	28,757	56,633	56,633
	2		122,316	30,770	91,546	148,179
	3		130,878	32,924	97,954	246,133
	4		140,040	35,229	104,811	350,944
	5		149,842	37,695	112,147	463,091
	6		160,331	40,333	119,998	583,089
	7		171,555	43,157	128,398	711,487
	8		183,563	46,177	137,386	848,873
	9		196,413	49,410	147,003	995,876
V. H.F. - (One Way)		808,964				
	1		85,390	31,499	53,891	53,891
	2		122,316	33,704	88,612	142,503
	3		130,878	36,063	94,815	237,318
	4		140,040	38,588	101,452	338,770
	5		149,842	41,289	108,553	447,323
	6		160,331	44,179	116,152	563,475
	7		171,555	47,272	124,283	687,758
	8		183,563	50,581	132,982	820,740

EXHIBIT 3--N

CASE #4SUMMER PEAKING - RURAL SYSTEM

Case #4 examines load control from the perspective of a rural coop in the south central section of the country.

This utility covers an area of flat terrain approximately rectangular in shape and with dimensions of 60 miles by 30 miles. The population is distributed throughout the area with some concentration occurring in and around small towns serving the rural communities. The electrical network consists of fifteen transformer substations, each of which feeds a 12 KV radial type distribution network. Facilities are provided for interconnection of the 12 KV systems but section points are normally operated in the open position.

The majority of the distribution substations are fed from a 69 KV loop system which in turn derives its source from a 138 KV bulk power transmission network. Two distribution substations are fed directly from the 138 KV system. Although not directly owned by the distribution authority, the EHV system is part of a multi-coop-owned generation and transmission organization of which the distribution authority is a member. Small portions of the distribution system remain fed from sources other than those described above but these are planned to be incorporated into the main system in the near future.

The system experiences maximum demands in the summer months reaching 60 MW in the early evening hours of a day in July or August. Winter peak demands are approximately 12% less and reach about 53 MW in January again in the evening hours between 6 p.m. and 9 p.m.

Of the approximately 13,000 residential customers served by the system, 3,706 or 28% have central air conditioners. However, even more customers (3,773) have electric water heaters. A total of 2,755 or 21% of all residential customers have both central air conditioning and electric water heaters. Because of the saturation of these two heavy use appliances and further, because of the fairly close margin between summer and winter peak demands, control of both air conditioner and water heating loads is considered in this illustrative case.

Load Control Strategy

The load control strategy was determined by first simulating both the total system and controllable loads. In this simulation the controllable load consisted of both water heaters and air conditioners. The system peak day load profile is shown in Exhibit 4-A. As this exhibit illustrates, the peak demand occurred at 7 PM (56,480 KW). The maximum controllable load was calculated to be 6,429 KW:

$$3,773 \text{ water heaters} \times 0.6 \text{ KW/heater (diversity at peak)} \times 1.0989 \text{ (loss factor)} \\ \times 0.98 \text{ (control switch success rate)} + 3,706 \text{ air conditioners} \times 4.0 \text{ KW/A/C} \times 1.0989 \\ \times 0.98 \div 4.$$

The air conditioner control load had to be divided by four to account for the fact that the maximum allowable inhibit time was 15 minutes per hour. Subtracting the controllable load from the system peak established the control target at 50,000 KW.

The load curve was then reconstructed with all water heater and air conditioner loads removed as shown in Exhibit 4-E. The diversity curve utilized for water heaters was obtained from Consumer's Power test data. This curve most accurately reflected the characteristics of the water heaters used in the economic analysis and was representative of water heater curves published in this area. This curve is shown in Exhibit 4-B. The diversity curve utilized for air conditioners was obtained from Georgia Power and can be seen in Exhibit 4-C.

As before, the water heater population was divided into 10 groups and the air conditioners into 8 groups. Group demands were switched off as necessary to keep the resultant demand below the control target with two objectives in mind: equal distribution of control time among all groups and minimizing control time as much as possible. Groups were then restored when system load dropped adequately below the control target.

The inhibit and restore schedules necessary to achieve these objectives are illustrated in Exhibits 4-D and 4-E.

Restore demand curves for the water heaters were derived from Detroit Edison data shown in Section III of this report. These curves were extended to obtain the longer off-times experienced in this simulation. Restore demand data for air conditioners was also obtained from Detroit Edison tests. These tests, performed on 36 homes, revealed that the "catch-up" or restore necessary for air conditioners to achieve the same level of comfort as before a five hour control period was 3 to 4 hours. Note that this was not the same assumption made in the Summer Peaking Urban case and was done to isolate the effect of varying the restore period. (There exists a paucity of data on the restore effects of air conditioner control, so that there is no consensus on which restore information is more valid.)

Given these assumptions, control was initiated at 2:07 PM when it became necessary to inhibit one group of air conditioners from coming on. Demand was reduced (as shown in Exhibits 4-D and 4-E) by 1,650 KW: $463 \text{ air conditioners} \times 3.3 \text{ KW/A/C}$ (diversified demand at time of inhibit) $\times 1.0989 \times 0.98$.

After 7-1/2 minutes, Group 1's inhibit was removed and Group 2's was initiated.

Cycling' of inhibits continued until 3:30 PM when it became necessary to inhibit

2 A/C groups at a time because of accelerating load growth. Two group cycling was maintained for the duration of the control period.

No more than 2 air conditioner groups could be inhibited at any one time because of the imposed limitation of 15 minutes of off time in any one hour. (This restriction was necessary to minimize customer discomfort.) As a result, control of water heaters was initiated at 3:52 PM to keep total demand below the control target. By 4:45 all but 3 water heater groups were inhibited. No cycling was used in control of water heater groups. By 6:45 all water heater groups were off and all air conditioner groups were cycling.

A major assumption in the air condition demand curves was that, after two cycles of control, air conditioners would assume a maximum diversified demand value of 4 KW. This was the observation in the Arkansas tests.

The system load curve did not diminish enough to permit any restoration of controlled load until 11:30 PM.

At this time, two water heater groups were restored. Restoration was allowable by the following calculations:

1. At 11:30, 75% of all air conditioners were permitted to run - all groups having cycled more than twice. The resultant A/C load is 12.0 MW;
 $2,780 \text{ air conditioners} \times 4 \text{ KW} \times 1.0989 \times .98$. The 12.0 MW is marked up from the green line in Exhibit 4-E (Load Profile without A/C or heaters) and is labeled 'total air conditioner demand'.
2. The resultant point is still approximately 2 MW short of the control target of 50 MW. Therefore, restore is possible at this time.

3. Group 1 (water heaters) has been off for 7.5 hours by 11:30. According to the available restore curves, its demand at time of restore will be 4.9 times the demand when it was first inhibited. This results in an average restore demand of 1.84 KW per unit and a total demand of 796 KW for the 377 water heaters in Group 1 after adjustment for losses and switching failures.
4. Group 2 has been off for 7:15 hours by 11:30. Using the same analysis as above, the demand at restore is 905 KW.
5. The two groups added together represent a returning demand of 1700 KW. Since 2,000 KW is available, groups 1 and 2 are easily restored at this time.
6. The demand levels in these groups will decay over 4 to 6 hours to the normal coincident demand as shown in the footnotes of Exhibit 4-D.

By 12:00 four more heater groups were restored using the same reasoning as above (despite the fact that all air conditioner groups have been restored). Total air conditioner load was therefore 15,964 KW ($.98 \times 3,706 \times 4$ KW (max. diversified demand) $\times 1.0989$). Therefore, 16.0 MW instead of 12.2 MW is now added to the bottom line ("load profile without A/C or heaters") in Exhibit 4-E to develop the "Total Air Conditioner Demand" Curve. The difference being the load available to restore heaters.

Proceeding further in this manner, all water heaters were restored by 12:45 with the longest off time being 8 hours.

In summary, the load control strategy for Case 4, a summer peaking rural utility, consisted of controlling 3,773 water heaters in ten groups and 3,706 central air conditioners in eight groups. Air conditioner groups were inhibited first, by cycling the groups on and off in sequential 7-1/2 minute intervals over an average period of 10 hours. Water heater groups were utilized as a 'reserve' controllable load and were inhibited an average of 7 hours. Air conditioner payback was assumed to extend over a 3-1/2 hour period.

The controllable load of 6.4MW represented 11.3% of the system peak load of 56.5 MW.

Development of Control System Costs

Control costs are developed for each of four generic types of control systems, and, for illustrative purposes, both costs and benefits are developed on the basis of a 100% acceptance rate by both air conditioner and water heating customers. Because of saturation redundancy, this would include a total of 4,724 customers of whom 1,018 have only water heaters, 951 have only air conditioners and 2,755 have both.

1. The Cost of Acquiring and Installing Control Apparatus

Installed system costs include both direct and indirect charges representing actual costs due vendors or other costs incurred by the utility in connection with the acquisition or installation of control facilities. Details supporting the development of overall installed costs for each of four generic types of control systems are included in Exhibit 4-G. Each estimate used as a basis the actual conditions prevailing at the location under study both in terms of system configuration and physical requirements.

For each system, a common central control readout and logic is assumed for the detection of peak load conditions and initiation of load control action. It is likely that essential data would be telemetered to central control from a single 138 KV injection point. One additional telemetering point is added to confirm time of peaks in recognition of possible differences in customer characteristics in different areas of the system.

Pertinent features of alternate types of installation in the specific operating environment investigated are as follows:

- a. Radio - The utility's experience with a presently installed two-way voice VHF radio system indicates that adequate coverage of the entire distribution area may be achieved with a single transmitter. Costs

for a Radio Control System, detailed in Exhibit 4-G-I, are predicated on the joint use of such common facilities as transmitter housing, power supply and antenna tower representing a significant cost savings. Total estimated costs for a Radio Control System are summarized below.

Radio Control System

Direct costs including spares	\$481,650
Indirect costs including contingencies	118,465
Total Installed cost	<u>\$600,115</u>

- b. Hybrid: Radio and Power Line Carrier - The radio portion of this system carries with it the same cost savings recognized above. In addition, shared use of the VHF transmitter appears feasible. As developed in Exhibit 4-G-II and summarized below, system costs suffer somewhat from the rural nature of the study area as reflected in the fact that only about 1.2 customers are served from each local distribution transformer. As a result, VHF and carrier current receiver costs are virtually borne by individual customers.

Hybrid Control System

Direct costs including spares	\$ 776,810
Indirect costs including contingencies	271,418
Total Installed cost	<u>\$1,048,228</u>

- c. Low Frequency Power Line Carrier - As the system now exists, the application of a low frequency power line carrier is encouraged in that the system may be covered effectively by the use of a single 138 KV injection point. For estimation of purposes, two additional medium voltage injection points are added although future system modifications may render these unessential. It must be recognized

that although single point injection represents the most economic present application, it is somewhat vulnerable to system changes.

The LF Power Line Carrier case is developed in both its simpler rhythm version and as a more complex multibit coded system. With the number of potentially controllable loads available, the multibit version would appear to have little justification other than the additional versatility offered with respect to future control extensions. Costs associated with the respective Power Line Carrier scenarios are detailed in Exhibits 4-G-III and 4-G-IV and are summarized below.

	LF POWER LINE CARRIER	
	<u>Rhythm</u>	<u>Multibit</u>
Direct costs including spares	\$694,825	\$ 886,974
Indirect costs including contingencies	206,601	209,706
Total Installed cost	<u>\$901,426</u>	<u>\$1,096,680</u>

- d. High Frequency Power Line Carrier - Application of the high frequency system with its requirement for injection at the medium voltage level on this type of system (rural) resulted in a conflict between the substation installed type and line installed type of sector injection unit. The use of partially loaded (50% capacity) line units was finally assumed resulting in a somewhat more economic installation. The use of the relatively low 50% capacity is due to the scattered nature of the area.

As a conservative measure, connection of the injection units to the central control is assumed to be via individual telephone lines although it is recognized that shared use is probably more realistic.

High frequency power line carrier, when used for purely peak load control, appears uneconomic even though it is simpler in application

and less susceptible to network changes than the low frequency system. On the other hand, the high frequency system has the distinct advantage of lending itself to other functions should two way communication applications be considered in future planning. Costs for the high frequency system are developed in Exhibit 4-G-V and are summarized below. In each case, only utilization for direct load control has been considered.

High Frequency Power Line Carrier (One Way)

Direct costs including spares	\$ 868,919
Indirect costs including contingencies	219,920
Total Installed cost	<u>\$1,088,839</u>

2. Operation and Maintenance Expense

Because of the relatively few points under control, it would not be necessary to have any Company personnel exclusively dedicated to the operation of any of the control systems. Operation costs would consist primarily of charges for leased telephone lines or those associated with a microwave channel as applicable for the respective systems. Anticipated maintenance costs consist primarily of personnel charges and consumable spares. Average annual O&M Expense estimates for each generic control system type are developed in Exhibit 4-H and are summarized as follows:

<u>Control System</u>	<u>Estimated Average Annual Operation and Maintenance Expense</u>
I. Radio	\$17,230
II. Hybrid	\$25,280
III. LF Power Line Carrier - Rhythm	\$38,386
IV. LF Power Line Carrier - Multibit	\$38,778
V. HF Power Line Carrier	\$40,770

Development of Estimated Capacity Cost Savings

Since, by definition, each of the utilities considered in this analysis is non-generating, that is, dependent upon external sources for power supply, it is evident that the overwhelming benefit of load control will be reflected in reduced capacity charges for purchased power. Since, under the control strategy formulated, overall energy consumption will remain relative unaffected, energy cost differentials would appear to be negligible.

Load studies undertaken to establish diversified water heater demands during system peak hours indicate a .8 KW per water heater in the winter months and .6 KW in summer periods to be a conservative estimate. These seasonal levels are adopted for purposes of this analysis.

Based on load studies performed by other utilities with generally similar weather conditions, a diversified demand of 4 KW per air conditioner is considered representative for this application. Under the load control strategy conceived for air conditioner control, however, only one out of four units would be under control at any one time. Consequently, a diversified demand of 1 KW per installation is proper to establish the impact of air conditioner control.

In order to extrapolate control point demands to the point of wholesale delivery to the system, distribution losses must be recognized. For illustrative purposes, it is assumed that system losses under peak conditions represent approximately 9% of delivered kilowatts. Finally, it must be anticipated that some portion of the load control devices may not be operational at any given time. In recognition of this factor, a 2% failure rate is incorporated in the development of total potentially controllable air conditioning loads. This determination may then be expressed as:

$$C = \frac{ND(1-F)}{1-L}$$

Where:

C = Controlled Air Conditioning Load
 N = Number of Controlled Air Conditioners
 D = Diversified Demand per Air Conditioner
 F = Failure Rate
 L = System Losses

During summer months, joint control of water heaters and air conditioners would represent a combined reduction of peak demand of the following magnitude:

$$C = \frac{[(3,706 \times 1.0 \text{ KW}) + (3,773 \times .6 \text{ KW})] (1-.02)}{(1-.09)} = \underline{\underline{6,429 \text{ KW}}}$$

For the winter months, of course, only the water heater load would be affected, and that at the average .8 KW per unit. All other factors remaining constant, total controlled load is:

$$C = \frac{(3,773) (.8 \text{ KW}) (1-.02)}{(1-.09)} = \underline{\underline{3,251 \text{ KW}}}$$

The wholesale rate under which the utility purchases power provides for a demand charge of \$2.45 per KW and a 100% demand ratchet based on the peak demand over the 12 month period ending with the current month. Because of this ratchet clause, no capacity cost savings are realized until the eighth month of load control as reflected in Exhibit 4-J. Subsequent capacity cost savings as developed in this exhibit serve as the basis for load control benefits as included in the following analysis.

Evaluation of Load Control Costs and Benefits

The methodology proposed for cost/benefit analysis is predicated on a consideration of relative annual or annual equivalent costs and/or benefits as levelized. A further basic consideration of the proposed methodology is that it takes its perspective from the viewpoint of the ultimate consumer's revenue requirements.

Accordingly, control system costs are translated into annual fixed charges representing levelized costs to the ratepayer in the form of capital recovery and property taxes. Engineering economy studies frequently express such fixed charges through application of a levelized fixed charge rate recognizing each of the factors indicated above and other elements of fixed cost as appropriate.

Fixed Charge Rate

The model for the Summer Peaking-Rural System case is an electric cooperative. Consequently, the cost of money component of the fixed charge rate is based on the interest rate charged for REA type loans. Currently, the interest rate for Distribution Coop loans is generally 5% and this level is adopted in this analysis.

Depreciation in the context of a fixed charge rate is established as the sinking fund charge indicated at an interest (discount) rate equal to the cost of money over the estimated service life of the investment. This may be expressed by the following formula:

$$D = \frac{(1-s)i}{(1+i)^n - 1}$$

Where: i = interest (discount) rate
 n = service life
 S = salvage value

Then, for a discount rate equal to the cost of money (5.00%) from above, and service life estimated at 15 years and zero salvage:

$$D = \frac{.05}{(1.05)^{15} - 1} = \frac{.05}{1.0789} = .0463 = \underline{\underline{4.63\%}}$$

The cost of money and sinking fund depreciation together constitute the capital recovery factor.

Based upon an analysis of actual Company tax levels, property taxes are estimated at a fixed annual level of 0.50% of investment.

In summary, the Fixed Charge Rate developed for application in Case #4 is then:

Case #4 Fixed Charge Rate

Cost of Money	5.00%
Depreciation	4.63
Property Taxes	0.50
Fixed Charge Rate	<u>10.13%</u>

Development of Levelized Annual Fixed Charges

Levelized annual fixed charges for each generic type of control system are developed as the product of individual Installed Cost estimates and the Fixed Charge Rate as developed above:

	GENERIC TYPE				
	I (Radio)	II (Hybrid)	III (LF-Rhythm)	IV (LF-Multibit)	V (HF-One Way)
Installed Cost	\$600,115	\$1,048,228	\$901,426	\$1,096,680	\$1,088,839
Fixed Charge Rate	10.13%	10.13%	10.13%	10.13%	10.13%
Levelized Fixed Charges	\$ 60,792	\$ 106,185	\$ 91,314	\$ 111,094	\$ 110,299

It should be noted that for this illustrative case, we have assumed a 15 year life and zero salvage value for each generic type. Any variation in either factor would obviously result in a different Fixed Charge Rate. The purpose of the methodology proposed in, in fact, to provide a valid basis for comparison when such differences exist as between generic types.

Development of Levelized Annual O&M Expense

Current (1975) levels of operation and maintenance expense estimates have been developed above for each generic type control system. It is likely, however, that, because of wage and other price adjustments, the level of annual O&M expense will escalate over the life cycle assumed for each control system. To account for this probability, each expense stream as developed in Exhibit 4-K includes escalation at an estimated level of 7% per annum through 1989, the fifteenth year of operation.

Under the proposed Cost/Benefit methodology, O&M expense is developed as the annual equivalent of the present worth of alternative expense streams. Again, since in the instant case the same service life (15 years) is assumed for each system, the necessity for this treatment is not as apparent. However, for illustrative purposes, the procedure has been carried out in Exhibit 4-K. The Present Worth Factor for each year as applied to yearly expense in order to develop present worth is the result of the following formula:

$$PWF_n = \frac{1}{(1+i)^n}$$

Where:

PWF_n = Present Worth Factor for Year n
 i = Discount Rate (In this Case 5.00%)
 n = year

Then:

$$PW = 15 \frac{E_n}{(1+i)^n} \quad \text{where } E_n = \text{yearly expense}$$

$$n=1$$

Total Present Worth for each O&M Expense stream is further shown in Exhibit 4-K. In order to express the respective amounts in terms of annual equivalents, an annuity factor is applied. The annuity factor results from the following formula:

$$AF = \frac{i (1+i)^n}{(1+i)^n - 1} = .096342, \text{ where } i = .05 \text{ and } n = 15$$

On an annual equivalent basis, the O&M Expense component for each generic system is then:

	GENERIC TYPE				
	I	II	III	IV	V
Present Worth of Annual Expense	\$281,834	\$413,507	\$627,883	\$634,292	\$666,877
Annuity Factor	.096342	.096342	.096342	.096342	.096342
Annual Equivalent	<u>\$ 27,152</u>	<u>\$ 39,838</u>	<u>\$ 60,492</u>	<u>\$ 61,109</u>	<u>\$ 64,248</u>

Development of Levelized Capacity Cost Savings

For purposes of this analysis, load control system benefits are equated to savings in the capacity cost component of purchased power. The determination of current savings levels has been previously discussed and is detailed in Exhibit 4-J. As with other operating expenses, it is reasonable to assume that purchased power expense; and hence, capacity cost levels would continue to escalate in the future.

Recognizing this factor and applying the same technique previously described for O&M Expenses, the annual equivalent of the present worth of future capacity cost savings is developed as shown in Exhibit 4-I. Levelized annual capacity cost savings are calculated at \$264,414.

Summary of Costs and Benefits and Development of Benefit/Cost Ratio and Payback Periods

Exhibit 4-M summarizes levelized annual costs and capacity cost savings for each load control system type analyzed.

The Benefit/Cost Ratio is favorable in each instance as further demonstrated in Exhibit 4-M and summarized below:

	GENERIC TYPE				
	I	II	III	IV	V
Benefit/Cost Ratio	<u>3.01</u>	<u>1.81</u>	<u>1.74</u>	<u>1.54</u>	<u>1.51</u>

As a further measure of project viability, the Payback Period defined as the period necessary to recoup project costs through accumulated net savings, is developed for each system analyzed in Exhibit 4-N.

Sensitivity Analyses

The Benefit/Cost Ratios developed above are predicated, among other things, upon

1. 100% Acceptance Rate by all potential load control customers
2. Escalation of future Capacity Cost Savings @ 7% p a

Obviously, actual circumstances could depart from those assumptions underlying this analysis.

In order to measure the impact of variations in either of these analysis components, we have prepared Exhibit 4-P in order to demonstrate levelized costs and benefits at acceptance rates varying from 0 to 100%. For this purpose, Load Control System costs were separated between fixed (central facilities, etc.) and variable (receivers, unit installation, etc.) components with the fixed portion applying even at 0% acceptance and variable costs incrementing with additional connections. It should be noted that this graph was prepared on the basis of specific data for the case under analysis and should not be construed as being a general representation.

Exhibit 4-P also depicts capacity cost savings at various acceptance levels without escalation. It may be seen that even on this basis, favorable Benefit/Cost ratios would result in all cases at 100% acceptance. Full acceptance would be required for System V, at least a 96% acceptance rate would be required for the System IV and other levels varying down to a minimum of 10% for the radio system.

Customer Incentives

On a break-even basis, monthly customer incentive could be offered at a maximum level represented by the following:

$$CI = \frac{.0833 (B_1 - C_1)}{N}$$

Where:

CI = Customer Incentive
 B₁ = Annual Equivalent Benefit for Generic Type 1
 C₁ = Annual Equivalent Cost for Generic Type 1
 N = Number of Appliances Controlled

From data developed above, maximum monthly customer incentive for the radio control system at the 100% acceptance rate would then be:

$$CI = \frac{.0833(264,414 - 87,944)}{7,479} = 14,700 = \underline{\underline{\$1.97 \text{ per appliance per month}}}$$

EXHIBIT 4A
CASE STUDY 4
SUMMER PEAKING RURAL UTILITY
SYSTEM PEAK DAY LOAD PROFILE

EXHIBIT 45
CASE STUDY 4
SUMMER PEAKING RURAL
TYPICAL SUMMER LOAD PROFILE - WATER HEATERS

EXHIBIT 4C
CASE STUDY 4
SUMMER PEAKING RURAL
TYPICAL SUMMER LOAD PROFILE
CENTRAL AIR CONDITIONERS

EXHIBIT 4-D

SUMMER PEAKING RURAL UTILITY - CONTROL SEQUENCE AT PEAK DAY

GIVEN: System Peak: 56,480 KW at 7PM
 Max. Controllable Load: 6,429 KW
 Control Target: 50,050 KW
 Group Sizes: 377 (WH), 463 (A/C)

INHIBIT SEQUENCE - 1st Phase

TIME OF INHIBIT	MINIMUM DEMAND REDUCTION NEEDED - NEXT 7.5 MINUTES	GROUP DEMAND AT TIME OF INHIBIT	NUMBER GROUP INHIBITED	TOTAL LOAD SHED	RESULTANT DEMAND WITH A/C CONTROL ONLY
2:07.5	200 KW	463 x 3.3 KW x LF + .98 = 1,650 KW	1	1,650 KW	48,400
2:15	300 KW	" x 3.35 KW x LF + .98 = 1,670 KW	1	1,670 KW	48,500
2:22.5	500 KW	" x 3.35 KW " " = 1,670 KW	1	1,670 KW	48,600
2:30	700 KW	" x 3.35 KW " " = 1,670 KW	1	1,670 KW	49,000
2:37.5	800 KW	" x 3.36 KW " " = 1,680 KW	1	1,680 KW	49,000
2:45	1,000 KW	" x 3.40 KW " " = 1,690 KW	1	1,690 KW	49,300
2:52.5	1,200 KW	" x 3.41 KW " " = 1,690 KW	1	1,690 KW	49,400
3:00	1,300 KW	" x 3.45 KW " " = 1,700 KW	1	1,700 KW	49,500
3:07.5	1,600 KW	" x 3.47 KW " " = 1,730 KW	1	1,730 KW	49,700
3:15	1,700 KW	" x 3.49 KW " " = 1,740 KW	1	1,740 KW	49,900
3:22.5	2,000 KW	" x 3.50 KW " " = 1,750 KW	1	1,750 KW	50,000
3:30	2,300 KW	" x 3.50 KW " " = 1,750 KW	2	3,500 KW	48,400
3:37.5	2,500 KW	" x 3.60 KW " " = 1,800 KW	2	3,500 KW	48,800

INHIBIT SEQUENCE - 2nd phase

<u>TIME OF INHIBIT</u>	<u>SYSTEM DEMAND EXCLUDING A/C</u>	<u>A/C * DEMAND</u>	<u>TOTAL DEMAND IF NO CONTROL (WH)</u>	<u>MINIMUM DEMAND REDUCTION NEEDED (KW)</u>	<u>WH GROUP DEMAND AT TIME OF INHIBIT</u>	<u># GROUPS NEEDED</u>	<u>TOTAL WH LOAD SHED</u>	<u>RESULTANT DEMAND</u>
3:45	37,800	12,200	50,000	0	--	0	0	50,000
3:52.5	38,000	12,200	50,200	150	377 x LF x .46 = 186	1	186	50,014
4:00	38,500	12,200	50,700	650	377 x LF x .45 = 186	4	728	49,972
4:07.5	38,500	12,200	50,700	650	377 x LF x .45 = 186	4	728	49,972
4:15	38,550	12,200	50,750	700	377 x LF x .45 = 186	4	728	50,022
4:22.5	38,550	12,200	50,750	700	377 x LF x .45 = 186	4	728	50,022
4:30	38,700	12,200	50,900	850	377 x LF x .42 = 170	5	850	50,050
4:37.5	38,750	12,200	50,950	900	377 x LF x .415 = 168	6	1000	49,950
4:45	38,850	12,200	51,050	1000	377 x LF x .4 = 162	7	1134	49,920
4:52.5	38,900	12,200	51,100	1050	377 x LF x .4 = 162	7	1134	49,966
5:00	38,980	12,200	51,180	1130	377 x LF x .4 = 162	7	1134	50,046
5:07.5	39,000	12,200	51,200	1150	377 x LF x .41 = 166	7	1162	50,038
5:15	39,100	12,200	51,300	1250	377 x LF x .53 = 215	7	1505	49,795
5:22.5	39,200	12,200	51,400	1350	377 x LF x .54 = 219	7	1533	49,867
5:30	39,225	12,200	51,425	1375	377 x LF x .55 = 223	7	1561	49,864
5:37.5	39,300	12,200	51,500	1450	377 x LF x .56 = 227	7	1589	49,911
5:45	39,375	12,200	51,575	1525	377 x LF x .57 = 231	7	1617	49,958
5:52.5	39,490	12,200	51,690	1640	377 x LF x .58 = 235	7	1645	50,045
6:00	39,500	12,200	51,700	1650	377 x LF x .585 = 237	7	1659	50,041
6:07.5	39,520	12,200	51,720	1670	377 x LF x .59 = 240	7	1680	50,040
6:15	39,800	12,200	51,950	1900	377 x LF x .595 = 242	8	1936	50,014
6:22.5	39,975	12,200	51,975	1925	377 x LF x .598 = 243	8	1944	50,031
6:30	39,775	12,200	51,975	1925	377 x LF x .598 = 243	8	1944	50,031
6:37.5	39,780	12,200	51,980	1930	377 x LF x .6 = 244	8	1952	50,028
6:45	40,000	12,200	52,200	1950	377 x LF x .6 = 244	10	2440	49,760

From 6:45 to 11:30 air conditioner groups continued to be controlled in pairs and all water heater groups remained off.

* Assumes 75% of total A/C running at max coincident demand: 3706 (A/C's) x 4 KW x 1.0989 x .75

Exhibit 4-D (Cont'd)

RESTORE SEQUENCE

<u>TIME OF RESTORE</u>	<u>SYSTEM LOAD BEFORE RESTORE</u>	<u>CONTROL TARGET</u>	<u>RESTORABLE LOAD</u>	<u>A/C LOAD RESTORE</u>	<u>WH LOAD RESTORE</u>	<u># WH GROUPS</u>	<u>RESULTANT SYSTEM LOAD AFTER RESTORE</u>
11:30	48,200	50,050	1850	0	1700 ⁽¹⁾	(2)	49,900
12:00	41,200	50,050	8850	3800 ⁽²⁾	4864 ⁽³⁾	(6)	49,864
12:15	43,700	50,050	6350	0	6285 ⁽⁴⁾	(8)	49,985
12:30	43,200	50,050	6850	0	6519 ⁽⁵⁾	(9)	49,719
12:45	42,500	50,050	7550	0	6856 ⁽⁶⁾	(10)	49,356
1:00	42,000	50,050	8050	0	6114 ⁽⁷⁾		48,114
1:30	40,600	50,050	9450	0	5462 ⁽⁸⁾		46,062

1:30 AM to 6:00 AM Air condition load's return to normal values three to four hours after the end of cycling. Water heaters return to normal coincident demand four to six hours after the control period. Using these guidelines and given the remaining restore levels, these last four hours were drawn by approximation.

FOOTNOTES TO RESTORE SEQUENCE:

1. WH Group 1 Restore: $377 \times 4.9 \times .4 \times 1.0989 \times .98 = 794\text{KW}$ (offtime 7.5 hours)
Group 2 Restore: $377 \times 4.85 \times .46 \times 1.0989 \times .98 = 906\text{KW}$ (offtime 7.25 hours)
Total Restore: 1700KW
2. A/C Group 2 Restore: $463 \times 4 \times 1.0989 \times .98 = 1994 \text{ KW}$ (total cycle control time 10 hours)
A/C Group 3 Restore: $463 \times 4 \times 1.0989 \times .98 = 1994$
Total Restore: 3998

(This represents the time when cycling control from air conditioners terminates - the system therefore sees all A/C at maximum coincident demand for up to four hours)

3. The water heater restore load at this time consists of four new groups coming back on plus the leakers in footnote #1 with thirty minutes of 'decrement'. The decrements are calculated using the referenced restore curves - only totals will be given here:

WH Group 1	Restore:	680	(30 minute decrement)
WH Group 2	Restore:	700	(30 minute decrement)
WH Group 3	Restore:	913	(off-time 8 hours)
WH Group 4	Restore:	913	(off-time 8 hours)
WH Group 5	Restore:	895	(off-time 7.5 hours)
WH Group 6	Restore:	835	(off-time 7.5 hours)
TOTAL		<u>4864</u>	

4. 8 water heater groups, including 2 new ones have the following restore values:

1	527	(45 minute decrement)
2	584	(45 minute decrement)
3	840	(15 minute decrement)
4	840	(15 minute decrement)
5	822	(15 minute decrement)
6	767	(15 minute decrement)
7	795	(off-time 7.5 hours)
8	<u>1110</u>	(off-time 6.0 hours)
<u>6285</u>		

Footnotes to Restore Sequence:

5. 9 water heater groups - restore values:

1	462	(1 hour decrement)
2	511	(1 hour decrement)
3	585	(30 minute decrement)
4	685	(30 minute decrement)
5	685	(30 minute decrement)
6	639	(30 minute decrement)
7	730	(15 minute decrement)
8	1026	(15 minute decrement)
9	<u>1096</u>	(off-time 5.75 hours)
	6519	

6. 10 water heater groups - restore values:

1	414	(1.25 hour decrement)
2	465	(1.25 hour decrement)
3	593	(45 minute decrement)
4	593	(45 minute decrement)
5	593	(45 minute decrement)
6	554	(45 minute decrement)
7	608	(30 minute decrement)
8	893	(30 minute decrement)
9	1023	(15 minute decrement)
10	<u>1120</u>	(off-time 6.0 hours)
	6856	

7. At this time all water heater groups are restored and have values attenuating from peak values as follows:

1	373	(1.5 hour decrement)
2	420	(1.5 hour decrement)
3	538	(1 hour decrement)
4	538	(1 hour decrement)
5	538	(1 hour decrement)
6	520	(1 hour decrement)
7	527	(45 minute decrement)
8	724	(45 minute decrement)
9	901	(30 minute decrement)

Footnotes to Restore Sequence:

8. This last monitored data point is listed to show how water heater demand levels are 'dampening down' two hours after the first groups were restored.

WH Group	1	300	(2.0 hour decrement)
	2	365	(2.0 hour decrement)
	3	465	(1.5 hour decrement)
	4	465	(1.5 hour decrement)
	5	465	(1.5 hour decrement)
	6	420	(1.5 hour decrement)
	7	414	(1.25 hour decrement)
	8	579	(1.25 hour decrement)
	9	621	(1 hour decrement)
	10	730	(.75 hour decrement)
		<u>4824</u>

EXHIBIT 4F
CASE STUDY 4
SUMMER PEAKING RURAL
WATER HEATER AND AIR CONDITIONER CONTROL
EFFECT ON SYSTEM LOAD PROFILE

EXHIBIT 4-G-IDOE LOAD CONTROL STUDY - NON GENERATING UTILITIESCase #4 - Summer Peaking Rural SystemDEVELOPMENT OF INSTALLED COST - VARIOUS GENERIC SYSTEMSSystem I - Radio

	<u>Amount Paid to Vendors</u>	<u>All Other Costs to the Utility</u>	<u>Total Cost</u>
<u>Direct Costs</u>			
1969 Single function receivers @ \$/0	\$138,830		
2755 dual function receivers @ \$115	316,825		
1 transmitter and antenna	7,000		
1 - antenna tower - joint use	-		
1 - micro wave channel - joint use	-		
2 - bulk supply point metering @ \$2,500	5,000		
2 x 2 circuit leased lines (78 circuit miles at \$60/circuit)		\$ 240	
1 - control center	4,500		
	<u>\$471,155</u>	<u>\$ 240</u>	<u>\$471,395</u>
Spares - 1 yr. operation			
39 - (2%) of single function receivers	\$ 2,730		
55 - (2%) of dual function receivers	6,325		
1 lot transmitter spares	700		
1 lot telemetering and control	500		
Total Spares	<u>\$ 10,255</u>		<u>\$ 10,255</u>
<u>Indirect Costs</u>			
Installation of 1969 single function receivers @ \$17		\$ 33,473	
Installation of 2755 dual function receivers @ \$24		66,120	
Installation of transmitter at 50 MH		900	
Installation of control and telemetering @ 50 MH		900	
Initial test 90 MH		1,620	
Contingency 15%		15,452	
		<u>\$118,465</u>	<u>\$118,465</u>
Total			<u>\$600,115</u>
Average cost/customer = \$127.04			
Average cost/function = \$ 80.24			

EXHIBIT 4-G- IIDOE LOAD CONTROL STUDY - NON GENERATING UTILITIESCase #4 - Summer Peaking Rural SystemDEVELOPMENT OF INSTALLED COST - VARIOUS GENERIC SYSTEMSSystem II - Hybrid: Radio & Power Line Carrier

	<u>Amount Paid to Vendors</u>	<u>All Other Costs to the Utility</u>	<u>Total Cost</u>
<u>Direct Cost</u>			
7479 end-use receivers @ \$45	\$336,555		
3749* VHF receivers @ \$110	412,390		
1 - transmitter complete - joint use	-		
1 master controller	6,000		
2 bulk supply point metering @ \$2,500	5,000		
2 x 2 circuit leased lines (78 circuit miles @ \$60/circuit		\$ 240	
1 control center	4,500		
	<u>\$764,445</u>	<u>\$ 240</u>	<u>\$764,685</u>
Spares - 1 yr. operation			
75 - (1%) end use VHF receivers	\$ 3,375		
75 - (2%) VHF receivers	8,250		
1 lot telemetering and control	500		
Total Spares	<u>\$ 12,125</u>		<u>\$ 12,125</u>
<u>Indirect Costs</u>			
Installation of 7479 end use receivers @ \$17		\$127,143	
Installation of 3749 VHF receivers @ 1.5 MH		101,223	
Installation of control and telemetering @ 50 MH		900	
Initial Test 3749 x 0.10 = 375 MH		6,750	
Contingency 15%		<u>35,402</u>	
		<u>\$271,418</u>	<u>\$271,418</u>
Total			<u>\$1,048,228</u>
Average cost/customer = \$221.89			
Average cost/function = \$140.16			

*Residential customers 12,890 transformers 10,628 average 1.21 customer/transformer

No. of VHF receivers assumed $\frac{4724}{1.26} = 3749$.

EXHIBIT 4-G-IIIDOE LOAD CONTROL STUDY - NON GENERATING UTILITIESCase #4 - Summer Peaking Rural SystemDEVELOPMENT OF INSTALLED COST - VARIOUS GENERIC SYSTEMSSystem III - LF Power Line Carrier, Rhythm Keying

	<u>Amount Paid to Vendors</u>	<u>All Other Costs to The Utility</u>	<u>Total Cost</u>
<u>Direct Cost</u>			
1969 single function receivers @ \$55	\$108,295		
2755 dual function receivers @ \$70	192,850		
1 set 138 KV injection equipment	160,000		
2 sets 25 KV injection equipment @ \$45,000	90,000		
1 - 138 KV substation switchgear bay		\$ 85,000	
2 - 25 KV bus connection and feeder @ \$2,500		5,000	
2 - bulk supply point metering @ \$2,500 (2 x 2) + (3 x 1) circuit, leased lines (78 + 76 circuit miles) at \$60 per circuit	5,000		
		420	
1 - control center	7,000		
	<u>\$563,145</u>	<u>\$ 90,420</u>	<u>\$653,565</u>
<u>Spares 1 yr. operation</u>			
20 - (1%) single function receivers	\$ 1,100		
28 - (1%) dual function receivers	1,960		
1 lot 138 KV injection spares	25,000		
1 lot 25 KV injection spares	12,000		
1 lot telemetering and control	1,200		
	<u>\$ 41,260</u>		<u>\$ 41,260</u>
<u>Indirect Cost</u>			
Installation of 1969 single function receivers @ \$17		\$ 33,473	
Installation of 2755 dual function receivers @ \$24		66,120	
Installation of 138 KV injection 320 MH + \$50,000		55,760	
Installation of 25 KV injection 2(240 MH + \$1,500)		17,460	
Installation of control and telemetering @ \$80 MH		1,440	
Initial tests 300 MH		5,400	
Contingency 15%		<u>26,948</u>	
		<u>\$206,601</u>	<u>\$206,601</u>
Total			<u>\$901,426</u>
Average Cost/Customer = \$190.81			
Average Cost/Function = \$120.53			

EXHIBIT 4-G-IVDOE LOAD CONTROL STUDY - NON GENERATING UTILITIESCase #4 - Summer Peaking Rural SystemDEVELOPMENT OF INSTALLED COST - VARIOUS GENERIC SYSTEMSSystem IV - LF Power Line Carrier, Multibit Code

	<u>Amount Paid to Vendors</u>	<u>All Other Costs to the Utility</u>	<u>Total Cost</u>
<u>Direct Cost</u>			
1969 single function receivers @ \$76	\$149,644		
2755 dual function receivers @ \$90	247,950		
1 set 138 KV injection equipment	260,000		
2 sets 25 KV injection equipment @ \$40,000	80,000		
1 - 138 KV substation switchgear bay		\$ 85,000	
2 - 25 KV bus connection and feeder @ \$2,500		5,000	
2 - bulk supply point metering @ \$2,500	5,000		
(2 x 2) + (3 x 1) circuit leased lines (78 + 76 circuit miles) at \$60 per circuit		420	
1 - control center	11,720		
	<u>\$754,314</u>	<u>\$ 90,420</u>	<u>\$ 844,734</u>
<u>Spares 1 yr. operation</u>			
20 - (1%) single function receivers	\$ 1,520		
28 - (1%) dual function receivers	2,520		
1 lot 138 KV injection spares	25,000		
1 lot 25 KV injection spares	12,000		
1 lot telemetering and control	1,200		
	<u>\$ 42,240</u>		<u>\$ 42,240</u>
<u>Indirect Cost</u>			
Installation of 1969 single function receivers @ \$17		\$ 33,473	
Installation of 2755 dual function receivers @ \$24		66,120	
Installation of 138 KV injection 320 MH + \$50,000		55,760	
Installation of 25 Kv injection 2(240 MH + \$1,500)		17,460	
Installation of control and telemetering @ 80 MH		1,440	
Initial tests 450 MH		-8,100	
Contingency 15%		27,353	
		<u>\$209,706</u>	<u>\$209,706</u>
Total			<u><u>\$1,096,680</u></u>
Average Cost/Customer \$232.15			
Average Cost/Function \$146.63			

EXHIBIT 4-G-VDOE LOAD CONTROL STUDY - NON GENERATING UTILITIESCase #4 - Summer Peaking Rural SystemDEVELOPMENT OF INSTALLED COST - VARIOUS GENERIC SYSTEMSSystem V - High Frequency Power Line Carrier

	<u>Amount Paid to Vendors</u>	<u>All Other Costs to the Utility</u>	<u>Total Cost</u>
<u>Direct Cost</u>			
4724 end use receivers @ \$95	\$ 406,030		
3773 load control relays @ \$25	94,325		
28 sector injection units @ \$9700	271,600		
28 sets 14.4 or 7.2 KV connection equipment @ \$400		\$ 11,200	
(28x1) + (2x2) circuit leased lines (286 circuit miles) @ \$60/circuit		1,800	
2 - bulk supply point metering @ \$2,500	5,000		
1 - control center	50,000		
	<u>\$ 826,955</u>	<u>\$ 13,000</u>	<u>\$ 839,955</u>
Spares 1 year operation			
94 - (2%) end use receivers	\$ 8,121		
2 - sector injection units	19,400		
38 - 1% load control relays	943		
1 lot - Telemetry and control	500		
	<u>\$ 28,964</u>		<u>\$ 28,964</u>
<u>Indirect Costs</u>			
Installation of 4724 end use receivers @ \$10		\$ 47,240	
Installation of 3773 load control relays @ \$17		64,141	
Installation of 3706 low voltage connections @ 15 each		55,590	
Installation of 28 sector injection unit @ 16 MH		8,064	
Installation of control and telemetering @ 320 MH		5,760	
Initial test @ 580 MH		10,440	
Contingency 15%		28,685	
		<u>\$219,920</u>	<u>\$ 219,920</u>
Total			<u><u>\$1,088,839</u></u>
Average cost/controlled customer = \$230.49			
Average cost/function =			

EXHIBIT 4-HDOE LOAD CONTROL STUDY - NON GENERATING UTILITIESCase #4 - Summer Peaking Rural UtilityDEVELOPMENT OF COSTS - VARIOUS GENERIC SYSTEMSV - Estimated Operation & Maintenance Expense

Page 1 of 2

	<u>MANHOURS</u>	<u>EXPENSE</u>
<u>I. RADIO</u>		
<u>Maintenance Labor</u>		
Xmitter - 0.5 day/month x 2 men	96	
Receivers - 99/year @ 1 MH each	99	
Complaints - 10/month @ 3 MH each	360	
Control - 0.5 MH/month	6	
Total	561 @ \$18	\$10,098
Leased Lines - 78 circuit miles		
@ 3.25/mile/month		3,042
Consumable Spares - 10,225 x 0.4		4,090
Total		\$17,230
<u>II. HYBRID</u>		
<u>Maintenance Labor</u>		
Xmitter (part of 2 way voice system)	0	
Receivers VHF-75/year @ 7 MH each	525	
Complaints - 10/month @ 3 MH each	360	
Control - 0.5 MH/month	6	
Receivers, End Use - 75 @ 1 MH each	75	
Total	966 @ \$18	\$17,388
Leased Lines - 78 circuit miles		
@ 3.25/mile/month		3,042
Consumable Spares - 12,125 x 0.4		4,850
Total		\$25,280
<u>III. PLC - LF RHYTHM</u>		
<u>Maintenance Labor</u>		
Receivers - 48/year @ 1 MH each	48	
Injection Points - Inspect 3 @ 8 MH		
/month	288	
Complaints - 15/month @ 3 MH each	540	
Control - 0.5 MH/month	6	
Total	882 @ \$18	\$15,876
Leased Lines - 154 circuit miles		
@ 3.25/mile/month		6,006
Subtotal		21,882
Consumable Spares - 41,260 x 0.4		16,504
Total		\$38,386
<u>IV. PLC - MULTIBIT CODE</u>		
Subtotal from above		\$21,882
Consumable Spares - 42,240 x 0.4		16,896
Total		\$38,778

EXHIBIT 4-HDOE LOAD CONTROL STUDY - NON GENERATING UTILITIESCase #4 - Summer Peaking Rural UtilityDEVELOPMENT OF COSTS - VARIOUS GENERIC SYSTEMSV - Estimated Operation & Maintenance Expense

Page 2 of 2

	<u>MANHOURS</u>	<u>EXPENSE</u>
V. PLC-III		
<u>Maintenance Labor</u>		
Receivers - 94/year @ 1.5 MH each	141	
Injection Points - Inspect 28 @ 2 MH each	56	
Injection Units - replace/repair 2/yr. @ 12 MH	24	
Complaints - 15/month @ 3 MH each	540	
Control - 2 MH/month	24	
Total	785 @ \$18	\$14,130
Leased Lines - 386 circuit miles @ \$3.25/m/mth		15,054
Consumable spares - 28,964 x 0.4		11,586
		<u>\$40,770</u>

EXHIBIT 4-JDOE LOAD CONTROL STUDY - NON GENERATING UTILITIESCase #4 - Summer Peaking Rural SystemDEVELOPMENT OF CAPACITY COST SAVINGS WITH LOAD CONTROL100% Central Air Conditioner & Water Heater Control

		<u>KW DEMAND, NO CONTROL</u>		<u>KW DEMAND, WITH CONTROL</u>		<u>DEMAND CHARGES</u>		<u>INDICATED SAVINGS</u>
		<u>Actual</u>	<u>Billing</u>	<u>Actual</u>	<u>Billing</u>	<u>No Control</u>	<u>With Control</u>	
1975	January	49,871	54,914	46,620	54,914	\$ 134,539	\$ 134,539	
	February	41,560	54,194	41,560	54,914	134,539	134,539	
	March	34,695	54,914	34,695	54,914	134,539	134,539	
	April	34,695	54,914	34,695	54,914	134,539	134,539	
	May	34,730	54,914	34,730	54,914	134,539	134,539	
	June	50,928	54,914	44,499	54,914	134,539	134,539	
	July	54,232	54,914	47,803	54,914	134,539	134,539	
	August	56,480	56,480	50,051	50,051	138,376	122,625	\$ 15,751
	September	50,842	56,480	44,413	50,051	138,376	122,625	15,751
	October	43,531	56,480	43,531	50,051	138,376	122,625	15,751
	November	41,832	56,480	41,832	50,051	138,376	122,625	15,751
	December	45,221	56,480	45,221	50,051	138,376	122,625	15,751
	Total 1975					<u>\$1,633,653</u>	<u>\$1,554,898</u>	<u>\$ 78,755</u>
1976	January	53,546	56,480	50,295	50,295	\$ 138,376	\$ 123,223	\$ 15,153
	February	44,622	56,480	44,622	50,295	138,376	123,223	15,153
	March	37,252	56,480	37,252	50,295	138,376	123,223	15,153
	April	37,252	56,480	37,252	50,295	138,376	123,223	15,153
	May	37,289	56,480	37,289	50,295	138,376	123,223	15,153
	June	54,681	56,480	48,252	50,295	138,376	123,223	15,153
	July	58,228	58,228	51,799	51,799	142,659	126,908	15,751
	August	60,642	60,642	54,213	54,213	148,573	132,822	15,751
	September	54,589	60,642	48,160	54,213	148,573	132,822	15,751
	October	46,739	60,642	46,739	54,213	148,573	132,822	15,751
	November	44,914	60,642	44,914	54,213	148,573	132,822	15,751
	December	48,554	60,642	48,554	54,213	148,573	132,822	15,751
	Total 1976					<u>\$1,715,780</u>	<u>\$1,530,356</u>	<u>\$185,424</u>

EXHIBIT 4-K

DOE LOAD CONTROL STUDY - NON GENERATING UTILITIES

Case #4 - Summer Peaking Rural System

DEVELOPMENT OF ANNUAL EQUIVALENT OPERATION & MAINTENANCE EXPENSE

Various Control Systems - Control @ 100% Acceptance Rate

	OPERATION AND MAINTENANCE EXPENSE FOR GENERIC TYPE (1) (2)					PRESENT WORTH FACTOR (3)	PRESENT WORTH FOR GENERIC TYPE (1)				
	I	II	III	IV	V		I	II	III	IV	V
1975	17,230	25,280	38,386	38,778	40,770	.952381	16,410	24,076	36,558	36,931	38,829
1976	18,436	27,050	41,073	41,492	43,624	.907029	16,722	24,535	37,254	37,634	39,568
1977	19,727	28,943	43,948	44,397	46,678	.863838	17,041	25,002	37,964	38,352	40,322
1978	21,107	30,969	47,025	47,505	49,945	.822702	17,365	25,478	38,688	39,082	41,090
1979	22,585	33,137	50,316	50,830	53,441	.783526	17,696	25,964	39,424	39,827	41,872
1980	24,166	35,457	53,838	54,388	57,182	.746215	18,033	26,459	40,175	40,585	42,670
1981	25,858	37,938	57,607	58,195	61,185	.710681	18,377	26,962	40,940	41,358	43,483
1982	27,668	40,594	61,640	62,269	65,468	.676839	18,727	27,476	41,720	42,146	44,311
1983	29,604	43,436	65,954	66,628	70,050	.644609	19,083	27,999	42,515	42,949	45,155
1984	31,677	46,476	70,571	71,292	74,954	.613913	19,447	28,532	43,324	43,767	46,015
1985	33,894	49,730	75,511	76,282	80,201	.584679	19,817	29,076	44,150	44,600	46,892
1986	36,267	53,211	80,797	81,622	85,815	.556837	20,195	29,630	44,991	45,450	47,785
1987	38,805	56,935	86,453	87,335	91,822	.530321	20,579	30,194	45,848	46,316	48,695
1988	41,522	60,921	92,504	93,449	98,249	.505068	20,971	30,769	46,721	47,198	49,622
1989	44,428	65,185	98,980	99,990	105,127	.481017	21,371	31,355	47,611	48,097	50,568
Total							281,834	413,507	627,883	634,292	666,877
						Annuity Factor 5%/15 Yrs.	.096342	.096342	.096342	.096342	.096342
						Annual Equivalent	27,152	39,838	60,492	61,109	64,248

NOTES: (1) Generic Types:

- I. - Radio
- II. - Hybrid - Radio & Power Line Carrier
- III. - Power Line Carrier (Low Frequency - Rhythm)
- IV. - Power Line Carrier (Low Frequency - Multibit)
- V. - Power Line Carrier (High Frequency)

(2) O&M Expense escalated @ 7% per year

(3) Discount Rate = 5%

EXHIBIT 4-LDOE LOAD CONTROL STUDY - NON GENERATING UTILITIESCase #4 - Summer Peaking Rural SystemDEVELOPMENT OF ANNUAL EQUIVALENT CAPACITY COST SAVINGSCentral Air Conditioner & Water Heater Control @ 100% Acceptance Rate

YEAR	CAPACITY COST SAVINGS		PRESENT WORTH	
	Calculated	Projected @ 7% Escalation	Factor (1)	Amount
1975	78,755		.952381	75,005
1976	185,424		.907029	168,185
1977		198,404	.863838	171,389
1978		212,292	.822702	174,653
1979		227,152	.783526	177,979
1980		243,053	.746215	181,370
1981		260,067	.710681	184,825
1982		278,271	.676839	188,345
1983		297,750	.644609	191,932
1984		318,593	.613913	195,588
1985		340,894	.584679	199,314
1986		364,757	.556837	203,110
1987		390,290	.530321	206,979
1988		417,610	.505068	210,921
1989		446,843	.481017	214,939
Total				2,744,534
		Annuity Factor 5%/15 Yrs.		.096342
		Annual Equivalent		<u>264,414</u>

NOTE: Discount Rate = 5%

EXHIBIT 4-M

DOE LOAD CONTROL STUDY - NON GENERATING UTILITIES

Case #4 - Summer Peaking Rural System

SUMMARY OF BENEFIT/COST RATIOS AND PAYBACK PERIODS

Various Control Systems - Control @ 100% Acceptance Rate

COST

Installed Cost	\$600,115	\$1,048,228	\$901,426	\$1,096,680	\$1,088,839
Fix Charge Rate	10.13%	10.13%	10.13%	10.13%	10.13%
Annual Fixed Charge - Levelized	60,792	106,185	91,314	111,094	110,299
Operation & Maintenance Expenses (Annual Equivalent of Present Worth)	27,152	39,838	60,492	61,109	64,248
Total Annual Cost - Levelized	<u>\$ 87,944</u>	<u>\$ 146,023</u>	<u>\$151,806</u>	<u>\$ 172,203</u>	<u>\$ 174,547</u>

BENEFIT

Annual Capacity Cost Savings by Reason of Water Heater Control - Levelized	<u>\$264,414</u>	<u>\$ 264,414</u>	<u>\$264,414</u>	<u>\$ 264,414</u>	<u>\$ 264,414</u>
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BENEFIT/COST RATIO

<u>3.01</u>	<u>1.81</u>	<u>1.74</u>	<u>1.54</u>	<u>1.51</u>
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PAYBACK PERIOD

Cumulative Net Savings Exceed Installed Cost in Year	<u>4.1</u>	<u>6.5</u>	<u>6.3</u>	<u>7.3</u>	<u>7.4</u>
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EXHIBIT 4-NDOE LOAD CONTROL STUDY - NON GENERATING UTILITIESCase #4 - Summer Peaking Rural SystemDETERMINATION OF PAYBACK PERIODSVarious Control Systems - Control @ 100% Acceptance Rate

	YEAR	INSTALLED COST	CAPACITY COST SAVINGS	OPERATING EXPENSES			NET SAVINGS	
				O&M Expenses	Property Taxes	Total	For Year	Cumulative
I. RADIO		600,115						
	1		78,755	17,230	3,000	20,230	58,525	58,525
	2		185,424	18,436	3,000	21,436	163,988	222,513
	3		198,404	19,727	3,000	22,727	175,677	398,190
	4		212,292	21,107	3,000	24,107	188,185	586,375
	5		227,152	22,585	3,000	25,585	201,567	787,942
II. HYBRID		1,048,228						
	1		78,755	25,280	5,241	30,521	48,234	48,234
	2		185,424	27,050	5,241	32,291	153,133	201,367
	3		198,404	28,943	5,241	34,184	164,220	365,587
	4		212,292	30,969	5,241	36,210	176,082	541,669
	5		227,152	33,137	5,241	38,378	188,774	730,443
	6		243,053	35,457	5,241	40,698	202,355	932,798
	7		260,067	37,938	5,241	43,179	216,888	1,149,686
III. L.F. RHYTHM		901,426						
	1		78,755	38,386	4,507	42,893	35,862	35,862
	2		185,424	41,073	4,507	45,580	139,844	175,706
	3		198,404	43,948	4,507	48,455	149,949	325,655
	4		212,292	47,025	4,507	51,532	160,760	486,415
	5		227,152	50,316	4,507	54,823	172,329	658,744
	6		243,053	53,838	4,507	58,345	184,708	843,452
	7		260,067	57,607	4,507	62,114	197,953	1,041,405
IV. L.F. MULTIBIT		1,096,680						
	1		78,755	38,778	5,483	44,261	34,494	34,494
	2		185,424	41,492	5,483	46,975	138,449	172,943
	3		198,404	44,397	5,483	49,880	148,524	321,647
	4		212,292	47,505	5,483	52,988	159,304	480,771
	5		227,152	50,830	5,483	56,313	170,839	651,610
	6		243,053	54,388	5,483	59,871	183,182	834,792
	7		260,067	58,195	5,483	63,678	196,389	1,031,181
	8		278,272	62,269	5,483	67,752	210,521	1,241,701
V. HIGH FREQUENCY		1,088,839						
	1		78,755	40,770	5,444	46,214	32,541	32,541
	2		185,424	43,624	5,444	49,068	136,356	168,897
	3		198,404	46,678	5,444	52,122	146,282	315,179
	4		212,292	49,945	5,444	55,389	156,903	472,082
	5		227,152	53,441	5,444	58,885	168,267	640,349
	6		243,053	57,182	5,444	62,626	180,427	820,776
	7		260,067	61,185	5,444	66,629	193,438	1,014,214
	8		278,272	65,468	5,444	70,912	207,360	1,221,574

EXHIBIT 4-P

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-
- (a) The year here shown is the date shown on the cover of the annual reports printed by the AEIC Load Research Committee
- (b) Also see Arkansas Power & Light Company and Georgia Power Company tests indexed below under "Central Air Conditioning Tests" (AEIC)
- (c) These two reports are also listed above under the heading "Central Air Conditioning Load Control Tests".

DEMAND CONTROL TESTS (a)

- (a) Also see Arkansas Power & Light Company and Georgia Power Company tests under "AEIC Load Research Committee Tests".

RESIDENTIAL ELECTRIC WATER HEATER DEMAND CONTROL TESTSWestern Massachusetts Electric Company

Report Date: May 3, 1973

Test Period: 11/30/71 - 11/28/72

Significant Findings & Comments (As Abstracted by Gilbert Associates)

1. This is a report of a test of the effect of radio control of electric water heaters in the Springfield, Massachusetts area which had heretofore been controlled by a time clock. The time clock had controlled only the lower heating element; that element could not operate between the hours of 3:00 PM to 10 PM, daily. Under the method of time clock control being used, the upper heater element was free to come on line at any time demanded by the tank's upper thermostat. The report was presented to the Meter and Service Committee of the Electric Council of New England at Newport, Rhode Island on May 3 by C. W. Prooty and R. K. Marble of the Western Massachusetts Electric Company.
2. Western Massachusetts Electric Company was already using a radio controlled system for voltage management. They decided to experiment with a radio control device as a substitute for synchronous time clocks, and to determine the maximum amount of load per water heater which could be turned off without undue customer complaint (page 1).
3. A primary voltage feeder was found on which there were 167 residences with two-element electric water heaters with interlock, mostly 4.5 KW heating elements. Two controls were installed at each water heater: one controlled only the top heating element; the other controlled the main water heater circuit, thus taking off the upper element as well as the lower. (Pages 1 and 2)
4. The only means of determining the effect of controlling the water heaters was by observing the curve-drawing watt meter chart of the primary voltage feeder circuit metering installation. The immediate change in load after initiating a control signal was taken to be the measure of kilowatts of water heater load on the line at the time of switching the water heaters off, and therefore a measure of the wattage which could be dropped by installing control devices. With the known number of water heaters controlled, the KW per water heater was calculated. (Page 4.)
5. The total water heater load (both heating elements) of each water heater was automatically inhibited for one burst of time of 5 to 7 minutes per hour, each hour, for a year and the results were logged. From such control and log the average KW per water heater was determined. (Page 4.) These results were logged and are plotted as "average day" load curves in Figures 2 to 8, inclusive. There is one chart for each of the 7 days of the week. On each chart is shown the diversified watts "per water heater switched off", there being three load curves per chart; namely the "high", the "low" and the "average" KW per water heater for each hour of the day for that day of the week.

6. The contribution of water heaters to the system peak is not indicated, nor is the month or hour of system peak indicated. Since the time clock control is set to prohibit the use of the lower heater element between 3 PM and 10 PM, it appears that the system peaks must usually occur in the "evening hours".
7. Conclusions:
 - a. Since all results are determined by reading a feeder wattmeter chart of large KW multiplier, one must conclude that all values obtained are only approximations. The smallest increment of reading - when estimated - is about 0.005, which is 14 KW on the basis of the recording chart multiplier of 2,800 KW. This amounts to 0.0838 KW per water heater if all of the 167 water heaters controllers were indeed actuated by the control tone. Thus, the results can be presumed to be no nearer than ± 0.1 KW of the stated values. (This paragraph is our conclusion.)
 - b. The maximum "average day" diversified demand per water heater usually occur between the hours of 10 AM and 2 PM or between the hours of 5 PM to 9 PM. (Figures 2 to 8 inclusive.)
 - c. Ignoring Saturday and Sunday, the maximum "average day" diversified demand per water heater was 1.69 KW on Tuesday at the hour ended 7 PM. The next highest was on Monday and was 1.68 KW at the hour ended 11 AM.
 - d. Since no information is given as to the water heater load at the system peak hour, and since no specific hourly data is supplied for any one day, one can only generalize (our conclusion) as to the range of KW reduction in demand which can be achieved.
 - e. The range of "KW per water heater available for switching off is assumed to be the "average" curve of the 7 daily curves. Data from that "average" is tabulated on the attached sheet.

WESTERN MASSACHUSETTS ELECTRIC COMPANY
 RADIO CONTROL OF WATER HEATERS, 12 Months Ended 11/26/72
 AT SPRINGFIELD, MASSACHUSETTS

DAY OF WEEK	AVERAGE KW PER WATER HEATER (a)			
	10 AM - 2 PM Inclusive (b)		5 PM - 9 PM Inclusive (b)	
	LOW	HIGH	LOW	HIGH
Monday	0.93 10 AM	1.04 12N	0.79 5 PM	1.10 7 PM
Tuesday	0.86 10 AM	0.99 12N	0.80 5 PM	1.07 7 PM
Wednesday	0.89 10 AM	0.99 12N	0.74 5 PM	1.00 7 PM
Thursday	0.91 10 AM	0.92 12N	0.67 5 PM	0.89 7 PM
Friday	0.92 10 AM	0.96 12N	0.78 5 PM	0.98 7 PM
Saturday	0.84 10 AM	1.09 12N	0.77 5 PM	1.02 7 PM
Sunday	0.76 10 AM	1.11 1 PM	0.75 5 PM	0.90 8 PM

Note: The water heaters (167 of them) were mostly 2-element, 4.5 KW each, with interlock, and without time control. Demands per water heater were calculated from the drop in the primary voltage feeder circuit load when all radio controls were actuated for a 5 to 7 minute period each hour.

(a) As tabulated from the average curve of Figures 2 to 8, inclusive of the report presented on May 3, 1973 to the Meter and Service Committee of the Electric Council of New England at Rhode Island.

(b) Times are "at the hour" specified.

RESIDENTIAL CENTRAL AIR CONDITIONING DEMAND CONTROL RESULTS

Cobb Electric Membership Corporation
Marietta, Georgia

Source of Data: An internal report by A. W. Barrett,
Manager of Electric Plant Operations
Time Period: 1976 and June, 1977 - September, 1977.

Significant Findings & Comments as Abstracted by Gilbert Associates, Inc.

1. This is a report of load reduction achieved by two different means:
(a) Radio control of central air conditioners in 1976 and 1977, and
(b) Additional load reduction, starting in the summer of 1977, by means of substation voltage reduction using 1 1/2% steps voltage regulators.
2. Central air conditioners radio controlled; no payment incentive to customers.
 - a. During 1976 about 5,000 individual central air conditioning units were being controlled, the average demand of which was 6.0 KW (page 6). For 1977 -- to be in service for the summer peak in July and August, 3,000 additional control units were installed. The average KW demand of the 8,000 air conditioning units was 5.25 KW (page 6). These values were obtained by simultaneously dropping all controlled air conditioners simultaneously and noting the load drop on a hot day, on several occasions (page 6).
 - b. On the June 13, 1977 peak day and hour with 26% curtailment of air conditioners (each cut off 7 out of each 27 minutes) the load reduction was 10,367 KW, or 1.296 KW per air conditioner.
 - c. On the July 21, 1977 system peak hour, curtailment of air conditioners was increased to 7 out of 20 minutes, or cut off 35% of the time, and the load reduction averaged 1.80 KW per air conditioner, or 14,437 KW. (pages 7 & 8)
 - d. Estimated pay-out time of controls for air conditioners, on basis of 1977 operations is 12 1/3 months, or 1.02 years (page 8).
 - e. The air conditioners were controlled on 32 different days during the 1977 summer months (page 9).
3. Voltage reduction by means of a SCADA system was instituted in June, 1977 in time for the July 21 peak. Among other functions, the system will command voltage regulators in 5/8% steps (1 1/2 volts steps at secondary level), up to 5 steps, or up to 7.5 volts at secondary level (page 2). Individual feeder and/or substation voltage regulators may be independently controlled.

- a. It was concluded on the basis of several tests that the maximum voltage reduction at the customer's premises at the weatherhead should be held to 6 volts, or 4 steps of reduction (page 5).
- b. On the basis of the 1977 demand reductions attained, at 4 voltage reduction steps (6.0 volts secondary), the SCADA system will pay back its investment cost in 6 1/2 months, or 0.53 years (page 8).
- c. The major problem of the SCADA system was poor leased telephone line reliability. The system used leased lines for issuing commands and retrieving data. (Pages 2 & 9.)

AEIC LOAD RESEARCH COMMITTEE REPORTS

Q U A L I F I C A T I O N

The Consultant has abstracted information from certain of the load research tests which have been printed in the "Report of the Load Research Committee" of the Association of Edison Illuminating Companies in various years. The abstracts presented herein and directed at providing specific information which may be helpful in estimating the kilowatt demand, per unit, which might be "dropped" from the system load of an operating utility company by controlling electric water heater loads and by controlling central air conditioning (summer cooling) loads. These abstracts, therefore, present only a portion of the information which is reported by the company in the "Report of the Load Research Committee".

The abstracts are taken from the reports printed by the Association of Edison Illuminating Companies (AEIC) Load Research Committee, and in no way purport to represent that the abstract is a finding of that Committee. The reports from which these abstracts are made are reports of individual companies, and are not an official position of the Committee.

Consultant's abstracts from various printed reports of the AEIC Load Research Committee herein presented have been reviewed by the individual utility company represented, and permission to here present the abstract has been obtained. Responsibility for correctness, and adequacy of the data expected rests entirely with the Consultant, and not with the company from whose printed tests the information has been extracted.

"Report Date" shown on the abstracts of the AEIC reports is the date of the report printed by the AEIC Load Research Committee. The "Test Period" is the dates covered by the test conducted by the Company.

RESIDENTIAL ELECTRIC WATER HEATER TEST RESULTS
AS REPORTED BY THE AEIC LOAD RESEARCH COMMITTEE

Baltimore Gas and Electric Co.

Report Date: 1964 - 1965 (AEIC)
Test Period: 12 Months Ended March 31, 1963

Significant Findings & Comments

1. This is a 12-month test of 23 residential quick recovery (QR) 40-gallon electric water heaters, each equipped with two 4.5 KW heating elements interlocked. The initial sample of 27 was reduced to 23. Complete test data ranged from 17 to 23 homes each month. At each home, one magnetic tape recorder was installed on the total home load and another was installed on the water heater. Average daily water temperature at a large pumping station was recorded. Also, the ground water temperature at a point 30 inches below ground level was obtained. Some of the conclusions reached were (see Page L-69):
 - a. Annual use of a 40-gallon quick recovery water heater with two 4.5 KW heating elements is about 1,470 hours' use of the connected load.
 - b. Fifty-five percent of the annual water heating energy requirements is on peak.(c)
 - c. The maximum water heating use is on Monday.
 - d. The daily maximum diversified demand usually occurs between 9:30 AM and noon.
 - e. A QR water heater adds one kilowatt to the Company's system peak, averaged over the one year period. (See Page 1-79.)
 - f. The high and low values of individual water heater maximum 30-minute demand during the test period was 1.9 and 5.1 KW.
2. Typical load curves of water heater demand per customer are presented on Charts A-17 to A-22 inclusive, attached hereto. Charts A-23 (attached) relates energy use to inlet water temperature.
3. Some of the data of Table A-18 is tabulated below:

(a), (b), (c), & (d) See next page for footnotes.

Baltimore Gas and Electric Co.
1964 - 1965 AEIC

	1963			1962								
	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.
Avg. Daily Water Temperature - °F	41	40	43	52	59	65	70	71	70	63	55	48
Avg. Daily Ground Temperature - °F	45	41	47	50	58	64	68	70	68	68	59	50
Water Heating KWH Per Customer	654	569	614	584	545	485	481	490	453	529	561	643(a)
Max. Coincident KW Per Water Htr.	2.4	2.3	2.3	2.6	2.5	2.1	2.2	2.0	2.0	2.2	2.0	2.7
Time: 1/2 Hr.												
Ended	10:00A	7:30P	8:30P	11:00A	11:30A	11:00A	12 N	10:00A	8:00P	9:30A	9:30A	11:00A
Day & Date	Mon. 7	Sat.16	Fri 15	Sat 21	Tue 29	Mon 4	Mon 23	Mon 27	Tue 18	Mon 15	Fri 2	Mon 31
Non-Coinc. Max. KW Per WH	4.6	4.5	4.6	4.6	4.6	4.6	4.6	4.5	4.4	4.5	4.5	4.5
Water Heater One-Hour KW Demand At Time of System Peak(b)	1.3	0.8	1.2	1.7	0.9	0.6	1.2	0.8	0.6	0.6	1.2	0.5
Hour Ended (No Date given)	7 PM	7 PM	8 PM	8 PM	2 PM	2 PM	2 PM	2 PM	2 PM	3 PM	6 PM	6 PM
Per Cent of Monthly WH KWH												
On-Peak 8 AM - 10 PM ^(c) - %	55	55	53	57	55	56	55	60	51	60	58	52(d)
Off-Peak Other Hours - %	45	45	47	43	45	44	45	40	49	40	42	48

(a) Total for the year is 6,608 KWH.

(b) Calculated from the table on Page L-82.

(c) "On-peak" is 8 AM to 10 PM, inclusive, on weekdays other than holidays.

(d) Annual: 55% on-peak and 45% off-peak KWH.

CHART A-17

Total Service and Quick Recovery Water Heating Load Curves
Baltimore, Maryland

CHART A-18

Total Service and Quick Recovery Water Heating
Average Weekday Load Curves
Baltimore, Maryland

CHART A-19

Quick Recovery Water Heating Load Curves
Baltimore, Maryland

CHART A-20

Total Service, Water Heating and System Load Curves
Day of System Peak, June 19, 1962 (Mean Temperature-82 F)
Baltimore, Maryland

CHART A-21

Total Service and Quick Recovery Water Heating Use
12 Months Ended March 31, 1963
Baltimore, Maryland

CHART A-22

Quick Recovery Water Heating Load Curves
Baltimore, Maryland

CHART A-23

Correlation of Quick Recovery Water Heating Energy Use
with Inlet Water Temperature
12 Months Ended March 31, 1963
Baltimore, Maryland

RESIDENTIAL ELECTRIC WATER HEATER TESTS RESULTS
AS REPORTED BY LOAD RESEARCH COMMITTEE OF AEIC

Consumers Power Company

Report Date: 1975-1976 (AEIC)
Test Period: 12 Months Ended June 30, 1975
(69 to 73 customers)

Significant Findings & Comments:

1. This is a report of a test of a sample of 75 non-seasonal, non-farm residential customers with electric water heaters, selected from the universe of 185,220 customers who were being billed on the Company's Rate A (Residential Service) or Rate A-1 (Residential Electric Heating Service), as of the date of the sample selection. The size of water heating element ranged from 5,500 to 1,000 watts for the upper element and from 5,500 to 500 watts for the lower element. One water heater had only one heating element (3,000 watts) and it was a 66-gallon tank size. All of the other water heaters had two heating elements. Water heater tank size ranged from 30-gallon to 82-gallon. Most of the water heaters on the company's system have elements which are interlocked. The interlock is not a Company requirement. Three customers in the study did not have the element interlocked. For various reasons, all of the 75 test customers' data does not appear in every month; there is data from 69 to 73 test customers in the various months. The test covered the 12 months ended June 30, 1975. At each test location a magnetic tape recording meter was installed to meter the total residence load and another magnetic tape recording meter was installed to meter only the water heater load. Thus, data is presented on "total residence" and on "water heater", separately.
2. Maximum diversified KW per WH ranged from a low of 1.01 on Monday, June 16, 30-minutes ended 11 AM to a high of 1.20 KW on Saturday, March 1 at 30-minutes ended 8:30 PM. The average of all 12 monthly values is 1.128 KW. (Pages L-144,145)
3. The time of occurrence of the maximum diversified demand, was as follows for the 30-minute period ended at the time shown: (Pages L-144,145)

Month	<u>JULY</u>	<u>AUG.</u>	<u>SEPT.</u>	<u>OCT.</u>	<u>NOV.</u>	<u>DEC.</u>	<u>JAN.</u>	<u>FEB.</u>	<u>MAR.</u>	<u>APR.</u>	<u>MAY</u>	<u>JUNE</u>
Day	Mon.	Mon.	Thur.	Sun.	Thur.	Sun.	Wed.	Wed.	Sat.	Sat.	Sat.	Mon.
Date	8	12	26	6	23	29	22	5	1	26	10	16
Time	10:30A	10:30A	8:30A	3:30P	11 A	1 PM	7 PM	8:30P	12:30P	8:30P	10 AM	11 AM
KW*	1.07	1.07	1.16	1.15	1.19	1.14	1.19	1.16	1.20	1.18	1.03	1.01

Consumers Power Company
1975-1976 AEIC

4. At System Peak Hour

Month	<u>JULY</u>	<u>AUG.</u>	<u>SEPT.</u>	<u>OCT.</u>	<u>NOV.</u>	<u>DEC.</u>	<u>JAN.</u>	<u>FEB.</u>	<u>MAR.</u>	<u>APR.</u>	<u>MAY</u>	<u>JUNE</u>
KW*	0.60	0.39	0.66	0.76	0.90	0.72	0.73	0.60	0.66	0.82	0.42	0.72
Day	Tue.	Wed.	Wed.	Tue.	Wed.	Mon.	Mon.	Mon.	Mon.	Wed.	Wed.	Mon.
Date	9	21	11	29	13	9	13	10	3	2	21	23
Time	1:30P	1:30P	2 PM	6 PM	6:30P	7 PM	11 AM	11 AM	10:30A	8 PM	1:30P	1:30P

5. Average Week Day of Test Max. Diversified KW:

KW*	0.68	0.71	0.80	0.80	0.81	0.78	0.87	0.80	0.82	0.79	0.69	0.66
1/2 Hour												
Ended	10:30A	11 AM	8:30P	8 PM	7 PM	7 PM	7:30P	7 PM	7 PM	7 PM	10 PM	11:30-A

* Water heater demands shown are on a 30-minute clock 1/2 hour basis.

6. Thus, in 8 of 12 months, on the basis of "average day", the maximum diversified demand per water heater occurs in the evening hours.
7. Graphic presentations are attached as pages L-154 to L-160 inclusive. (Charts C-6 to C-12 inclusive)
8. Test was of customers in lower peninsula of Michigan, 6,938 degree days of heating in the 12 months, as compared to a normal 6,931 weighted average degree-days.
9. The winter and summer "total residence" graphs virtually follow an identical path as that of the water heater load. Notable difference between the winter and summer charts include the magnitude of the demands and the greater water heater load as a percent of total residence load during the summer months.
10. Ground water temperatures are not supplied.

CHART C-6
Load Curves for Monthly System Maximum Demand
Days and Corresponding Diversified Demand Days
Total Load and Water Heating Load
July, 1974 - December, 1974
Michigan, Lower Peninsula

JULY 9, 1974

AUGUST 21, 1974

SEPTEMBER 11, 1974

OCTOBER 29, 1974

NOVEMBER 13, 1974

DECEMBER 9, 1974

Load Curves for Monthly System Maximum Demand
Days and Corresponding Diversified Demand Days
Total Load and Water Heating Load
January, 1975 - June, 1975
Michigan, Lower Peninsula

JANUARY 13, 1975

FEBRUARY 10, 1975

MARCH 3, 1975

APRIL 2, 1975

MAY 21, 1975

JUNE 23, 1975

CHART C-8
Load Curves for Water Heater and Total Load
Diversified Demand Days on Day of Winter
Water Heater Maximum Diversified Demand
Wednesday, January 22, 1975
Michigan, Lower Peninsula

CHART C-9
Load Curves for Water Heater and Total Load
Diversified Demand Days on Day of Summer
Water Heater Maximum Diversified Demand
Monday, July 8, 1974
Michigan, Lower Peninsula

CHART C-10
Load Curves for Water Heater and Total Load
Diversified Demand Days on Day of Annual
Water Heater Maximum Diversified Demand
Saturday, March 1, 1975
Michigan, Lower Peninsula

CHART C-11
Load Curves for Water Heater and Total Load
Diversified Demand Days on Day of Winter
Total Load Maximum Diversified Demand
Thursday, December 26, 1974
Michigan, Lower Peninsula

CHART C-12
Load Curves for Water Heater and Total Load
Diversified Demand Days on Day of Summer
Total Load Maximum Diversified Demand
Thursday, August 22, 1974
Michigan, Lower Peninsula

RESIDENTIAL ELECTRIC WATER HEATER TEST RESULTS
AS REPORTED BY THE AEIC LOAD RESEARCH COMMITTEE

Consumers Power Company

Report Date: 1963 - 1964 (AEIC)

Test Period: December 1, 1959 to December 31, 1961

Significant Findings & Comments:

1. This is a report of a test made of two groups of water heaters, consisting of a sample selection of 41 customers in each group. One group of 41 had controlled water heaters, the other group was uncontrolled. The test groups had about the same appliance saturation and the water heater tank sizes included all of the 5 sizes commonly used in the Company's service area. (The customers are located in South-Central Michigan.) The lower heating element of the controlled group of water heaters was controlled so that it could not operate between the hours of 9:30 AM - 11:30 AM and 4:30 PM - 6:30 PM. In all cases (controlled and uncontrolled) the elements were interlocked, with no time restriction on the upper heating element. A recording demand meter was installed on each water heater to record demand and kilowatt-hours use of the water heater. A watt-hour meter with demand attachment measured monthly total service KWH and peak demand of each test residence. Inlet water temperatures were obtained at various times throughout the period. The tests were conducted over two consecutive periods of time. In the first test, the time period was December 1, 1959 through November 30, 1959. In that first period all water heater elements were of NEMA standard wattage.^(a) The second period was January 1, 1961 to December 31, 1961. For the second period, the same test customers were retained, but all heating elements were replaced with 4.5 KW quick-recovery heating elements. The hours of control for the second test were the same as for the first test.
2. The hot-water-using appliance saturation, the distribution of tank sizes and the total residence connected load of the controlled group and of the uncontrolled group were similar. Annual test data was obtained for both years for 37 of the 41 test customers of each group.
3. The most common hours of occurrence of the maximum coincident demand per water heater were as follows:
 - a. For the uncontrolled group: NEMA standard wattage; 10 AM to 2 PM, or between 6 PM and 10 PM;
4.5 KW wattage; 8 AM to 12 noon, or between 6 PM and 8 PM.
 - b. For the controlled group: The maximum demands always occur soon after the end of each of the two "off" periods. The times of occurrence of the maximum demands are:
NEMA standard wattage; 12 noon to 2 PM and 7 PM to 9 PM;
4.5 KW wattage; 11 AM to 12 noon and 6 PM to 7 PM.

(a) Upper element, 30 watts per gallon of tank capacity. Lower element, 20 watts per gallon of tank capacity. In each case, the elements are to the nearest commercially available wattage, plus or minus.

Consumers Power Company
1963 - 1964 AEIC

4. The quick-recovery (4.5 KW) elements caused both the morning and evening peaks to occur earlier than they did with NEMA wattage, in both the controlled and uncontrolled groups.
5. The diversified maximum demand of the NEMA units is about the same as the lower heating element rating, but with the 4.5 KW heating elements it is substantially less than the rated 4.5 KW and is in the range of 1.7 to 2.2 KW (30-minute basis), controlled; and 1.1 to 1.7 KW uncontrolled.
6. Graphs of water heater load are presented in Charts CW-1, CW-2 and CW-3, copies of which are attached.
7. There is no data regarding contribution of water heater load to system peak hour demand in the months of the tests. Also, the date and time of occurrence of demands is not tabulated in the report. Inlet water temperatures are not reported nor charted.
8. The following is a tabulation, from Tables CW-1 and CW-2, of some of the data of interest.

	<u>JAN.</u>	<u>FEB.</u>	<u>MAR.</u>	<u>APR.</u>	<u>MAY</u>	<u>JUNE</u>	<u>JULY</u>	<u>AUG.</u>	<u>SEP.</u>	<u>OCT.</u>	<u>NOV.</u>	<u>DEC.</u>
<u>WITH NEMA STANDARD HEATER ELEMENTS, CONTROLLED</u>												
Number of test customers	38	41	28	41	39	39	39	39	40	39	38	38
Avg. Rating of Upper Element, KW	1.57	1.59	1.57	1.59	1.59	1.59	1.57	1.57	1.59	1.60	1.61	1.57
Avg. Rating of Lower Element, KW	1.00	1.02	1.00	1.02	1.02	1.02	1.02	1.02	0.97	1.02	1.03	1.00
<u>WITH NEMA STANDARD HEATER ELEMENTS, UNCONTROLLED</u>												
Number of test customers	34	38	38	41	41	41	40	40	41	40	40	25
Avg. Rating of Upper Element, KW	1.56	1.58	1.58	1.58	1.58	1.58	1.55	1.55	1.55	1.55	1.58	1.51
Avg. Rating of Lower Element, KW	1.00	1.01	1.01	1.01	1.01	1.01	1.00	1.00	1.00	1.02	1.02	1.07

Consumers Power Company
1963 - 1964 AEIC

	<u>JAN.</u>	<u>FEB.</u>	<u>MAR.</u>	<u>APR.</u>	<u>MAY</u>	<u>JUNE</u>	<u>JULY</u>	<u>AUG.</u>	<u>SEP.</u>	<u>OCT.</u>	<u>NOV.</u>	<u>DEC.</u>
<u>NO. OF TEST CUSTOMERS: 4.5 KW HTR. ELEMENTS</u>												
Controlled	38	38	37	38	36	37	36	36	35	36	36	36
Uncontrolled	35	35	37	36	35	36	35	35	34	35	35	34
<u>ENERGY USE PER CUSTOMER IN KWH</u>												
NEMA Units, Controlled	305	294	326	300	296	287	278	275	252	285	274	302
NEMA Units, Uncontrolled	313	314	354	324	322	300	285	296	267	290	300	297
4.5 KW Units, Controlled	327	319	341	332	324	288	263	269	281	287	286	316
4.5 KW Units, Uncontrolled	354	322	360	344	334	305	300	308	283	295	308	320
<u>MAXIMUM DIVERSIFIED (COINCIDENT) DEMAND PER CUSTOMER, IN KW (30-MINUTE)</u>												
NEMA Units, Controlled	0.9	0.9	0.9	0.9	0.8	0.8	0.8	0.8	0.9	0.9	0.9	0.9
NEMA Units, Uncontrolled	0.8	0.9	1.0	0.9	0.9	0.8	0.8	0.8	0.8	0.8	0.8	0.8
4.5 KW Units, Controlled	2.2	2.1	2.1	2.2	2.1	1.9	1.7	2.0	2.0	2.0	2.3	2.1
4.5 KW Units, Uncontrolled	1.7	1.3	1.4	1.4	1.6	1.4	1.1	1.2	1.4	1.3	1.3	1.3
<u>AVERAGE MAXIMUM NON-COINCIDENT DEMAND PER CUSTOMER, IN KW (30-MINUTE)</u>												
NEMA Units, Controlled	1.6	1.5	1.6	1.6	1.6	1.6	1.6	1.5	1.5	1.6	1.6	1.5
NEMA Units, Uncontrolled	1.4	1.6	1.6	1.5	1.5	1.4	1.5	1.5	1.5	1.5	1.5	1.4
4.5 KW Units, Controlled	4.4	4.4	4.3	4.4	4.3	4.2	4.3	4.1	4.3	4.3	4.3	4.3
4.5 KW Units, Uncontrolled	4.2	4.2	4.4	4.3	4.3	4.2	4.4	4.4	4.3	4.3	4.3	4.3

CHART CW-1

Electric Water Heating
Average Weekday Load Curves by Season
For Week of Maximum Average Weekday Diversified Demand
with NEMA Standard Elements
December 1, 1959 to November 30, 1960
South-Central Michigan

CHART CW-2

Electric Water Heating
Average Weekday Load Curves by Season
For Week of Maximum Average Weekday Diversified Demand
with 4.5 Kw Quick-Recovery Heater Elements
January 1, 1961 to December 31, 1961
South-Central Michigan

CHART CW-3

Electric Water Heating
Load Curves for Maximum Diversified Demand Day
December 1, 1959 to December 31, 1961
South-Central Michigan

RESIDENTIAL ELECTRIC WATER HEATER TEST RESULTS
AS REPORTED BY THE AEIC LOAD RESEARCH COMMITTEE

Detroit Edison Company

Report Date: 1969 - 1970 (AEIC)

Test Period: Dec., 1968 -- Nov., 1969

Significant Findings & Comments:

1. This is a report of a one-year test of sixty-five 50-gallon tanks, and sixty-six 80-gallon electric water heaters. One of the objectives of the test was to determine the diversified summer and winter demands of electric water heaters with radio-controlled lower heating elements.
2. Although the "tests" extended over a 12-month period, demand tests were made only in a two-week summer period and a two-week winter period. Kilowatt-hour consumption was obtained for most months of the test. An "Amprobe" recorder was installed for the two-week periods to record the "on" and "off" time of the heater elements. From the on time so determined, the KW demand was estimated. The average wattage used in the calculation was obtained by dividing the KWH registration of the watt-hour meter (in the two-week period) by the elapsed time obtained by reading the recorder tape.
3. Two rates schedules were in effect for water heating during the tests. One was a floating block rate with block size tied to water heater tank size. The other rate was a flat price per KWH, but the rate was not open to new business. On most of the water heaters the upper and lower heating elements were interlocked, but any found without interlocks were not changed.
4. The lower heating element non-coincident maximum demands averaged 2.4 KW for the 50-gallon test group and 3.1 KW for the 80-gallon test group.
5. Typical group coincident demands of the water heaters as stated on page L-145 are:

Weekday mid-day and evening peaks: 0.8 - 0.9 KW per water heater
6. Load reduction accomplished with radio control, per page L-145:

Summer: 50% reduction, or 0.40 to 0.45 KW reduction
Winter: 40% reduction, or 0.32 to 0.36 KW reduction
7. No specific information is given as to how long the water heaters were kept off the line by radio control.
8. No specific kilowatt values, other than stated in paragraph #6 above, are given for contribution to system peak hour.
9. Charts CW-1 through CW-3 (copies attached) present "typical" water heater load shapes for "controlled" and "uncontrolled" operation, but specific numerical values supporting the charts are not shown in the report.

CHART CW-1

Water Heater, Load Curves for Typical Weekdays,
Summer and Winter, With Controlled and Uncontrolled Operation
(Weighted Average Customer: 75% 50-Gallon; 25% 80-Gallon)
Detroit, Michigan

CHART CW-2

Water Heater Load Curves for Typical Summer and
Winter Weekdays by Tank Size
Detroit, Michigan

Load Research

CHART CW-3
Water Heater Load Curves for Typical Weekdays
By Tank Size and Rate
Detroit, Michigan

RESIDENTIAL ELECTRIC WATER HEATER TEST RESULTS
AS REPORTED BY THE AEIC LOAD RESEARCH COMMITTEE

Detroit Edison Company

Report Date: 1966 - 1967 (AEIC)

Test Period: May, 1965 - June, 1966

Significant Findings & Comments:

1. These tests include thirty 50-gallon and thirty 80-gallon water heaters. The KWH consumption of the upper heating element and of the lower heating element was separately metered and energy use was determined by reading the watt-hour meters once each month as well as more often during the period when demand data was being obtained during the three two-week test periods.
2. Hot water use was measured for a minimum of two weeks each in the summer and winter.
3. Demand data was obtained during three tests:

Two weeks each in summer and winter with lower element operation restricted by time clock to a 20-hour period daily.
Two weeks in the spring with the lower element uncontrolled.
4. The average KWH consumption per gallon of water heated ranges as follows:

50 gallon tank - 0.359 KWH per gallon of water heated
80 gallon tank - 0.319 KWH per gallon of water heated (Table CH-1)
5. KW demands determined during the test periods were as follows, per Table CH-1:

Average Weekday Demand (60-Minute)	<u>50 Gallon</u>	<u>80 Gallon</u>
At time of system peak		
Summer, 2 PM, usually		
Controlled	0.85	1.01
Uncontrolled	0.92	1.09
Winter, 7 PM, usually		
Controlled	0.07	0.07
Uncontrolled	0.83	1.20
Average Weekday KW, Maximum		
Controlled, Summer	0.98	1.39
Winter	1.04	1.55
Uncontrolled	1.06 (11 AM)	1.32 (9 PM)
Non-Coincident Max. KW, Per WH		
Lower Element	2.39	3.23
Upper Element	1.14	1.19

Detroit Edison Company
1966 - 1967 AEIC

6. Typical load curves of the water heater demand are shown in Chart CH-1, attached.
7. Chart CH-2 which shows the daily use of hot water for 50-gallon and 80-gallon tanks sizes, separately, is attached.

CHART CH-2

Cumulative Distribution of Hot Water Use
50-Gallon and 80-Gallon Water Heaters
Average Day and High Use Day of Test Period
Detroit, Michigan

L-175

CHART CH-1

Residential Water Heater
Average Weekday Load Curves
Detroit, Michigan

RESIDENTIAL ELECTRIC WATER HEATER TEST RESULTS
AS REPORTED BY THE AEIC LOAD RESEARCH COMMITTEE

Detroit Edison Company

Report Date: 1965 - 1966 (AEIC)
Test Period: Summer, 1965
Winter, 1965 - 1966

Significant Findings & Comments:

1. This is a report of tests of thirty 50-gallon and thirty 80-gallon electric water heaters. The KW demand data for the water heaters was obtained by a calculation based on the heater element "on" time as determined by a recording "Ampprobe" ammeter and based on the average KWH per hour which was calculated from the reading of the watt-hour meter and the operating "on" time calculated from the "Ampprobe" recording ammeter. It appears that cold water inlet water meter were installed and coupled with type G (General Electric ?) demand meters to record the pattern of water flow, but the test is not clear on this point. The water heaters are two-element, with interlock. The controlled lower element is restricted by time clock so it cannot operate at certain hours. The "off" time is "split"; that is, some lower elements are off from 5 PM to 9 PM and some are off on a dual period of 5 PM to 7:30 PM plus 9 PM to 10:30 PM. Total "on" period is 20 hours. Separate watt-hour meters were installed on the upper and lower heating elements.
2. Since KW demands are calculated from "on" periods read from a recording ammeter, the demand data here presented is a reasonable approximation, and all of the tabulated results should be qualified to that extent. The water use and kilowatt-hour use seem to be based on KW meter readings and seem to be accurate.
3. Water use per day averaged 75% of tank capacity. The average high use per day per customer exceeded tank capacity by about 75%. The highest one-hour use of water (all customer included) was 29 gallons per customer for the 50-gallon tanks and 41 gallons per customer for the 80 gallon tanks.
4. Energy use per gallon of hot water, averaged as follows:

 Winter Use: 50 Gal. -- 0.414 KWH per gal. of hot water
 Winter Use: 80 Gal. -- 0.343 KWH per gal. of hot water
 Summer Use: 50 Gal. -- 0.388 KWH per gal. of hot water
 Summer Use: 80 Gal. -- 0.310 KWH per gal. of hot water
5. The Company's annual system peak usually occurs in December at the hour ending at 6 PM, at which time the controlled lower element is not permitted to operate.

Detroit Edison Company
1965 - 1966 AEIC

6. The report estimates the following one-hour contributions to summer and winter system peak.

Summer peak - 1.0 KW per water heater (Hour and date not supplied.)
Winter peak - 0.1 KW per water heater (On a December day at hour ended 6 PM.)

7. The coincident one-hour maximum demands per customer in the two test periods were:

50 gallon: 1.50 KW on Monday at hour ended 10 AM on a Monday
80 gallon: 1.81 KW on Saturday at 11 PM to 12 MN. (Max. daytime demand of this group was on the same day at the hour ended 2 PM on the same Saturday.)

8. Some of the pertinent demand data is tabulated below from Tables CW-1 and CW-4. (Load shapes are shown in Charts CW-1 and CW-2, attached.)

	50- GALLON		80- GALLON	
	Summer	Winter	Summer	Winter
Customers in Sample	26	27	28	28
Average Family Size	4.0	4.1	5.0	4.9
Appliance Saturation in %				
Automatic Washers	68.0	65.4	77.8	74.1
Non-Automatic Washers	28.0	30.8	22.2	25.9
Dishwashers	4.0	7.7	22.2	22.2
Clothes Dryers	56.0	53.8	66.7	63.0
Test Periods:				
Energy Use Metered	6/11/65 --	3/31/66	7/1/65 --	3/31/66
Demand Data, 2 Weeks In:	Jun '65	Jan '66	Jul '65	Dec '65
Test Week	6/20-26	1/16-22	7/25-31	12/12-18
Water Use (Refer to Table CW-1)				
Inlet Water Temperature - °F	58	47	62	53
Average Wattage of Heater Unit:				
Lower Element(a)	2.33	2.36	3.18	3.16
Upper element(a)	3.50	3.64	3.46	3.41

(a) See next page for footnotes.

Detroit Edison Company
1965 - 1966 AEIC

	50-GALLON		80-GALLON	
	<u>Summer</u>	<u>Winter</u>	<u>Summer</u>	<u>Winter</u>
Non-Coincident Maximum Avg. KW				
Lower Element(b)	2.37	2.35	3.19	3.15
Upper Element(b)	0.37	1.12	0.70	1.04
Coincident Diversified Max. KW (d)				
In Test Week	1.24	1.50	1.68	1.81(c)
Day & Date	Mon 6/21	Mon 1/17	Sat 7/31	Sat 12/18
Hour Ended	12 Noon	10 AM	12 Noon	12 MN

- (a) By test at time of meter installation.
 (b) See paragraph #2, above.
 (c) The maximum daytime demand was on this same date; it was 1.75 KW at hour ended at 2 PM.
 (d) KW demands on a "time basis" were obtained only in one week in each of the months of June, 1965; July, 1965; December, 1965 and January, 1966.

CHART CW-1

Load Curves and Hourly Water Use
50-Gallon and 80-Gallon Water Heaters
Average Weekday, Summer and Winter
Detroit, Michigan

CHART CW-2

Load Curves and Hourly Water Use
50-Gallon and 80-Gallon Water Heaters
High Water Use Day, Summer and Winter
Detroit, Michigan

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RESIDENTIAL ELECTRIC WATER HEATER TEST RESULTS
AS REPORTED BY THE AEIC LOAD RESEARCH COMMITTEE

Houston Lighting and Power Company

Report Date: 1974 - 1975 (AEIC)

Test Period: 12 Months of 1974

(61 All-Electric Homes) HOURLY DEMANDS

Significant Comments & Findings:

1. At 42 of 61 test locations, the magnetic tape recorders in the all-electric homes were connected to separately record the water heater electric consumption. Data was complete for 37 of the 42 locations.
2. The maximum diversified one-hour demand, per water heater, occurred in the hours ended 8 PM to 11 PM except; March, 10 AM; September, 8 AM; November & December, 12 Noon.
3. One-Hour demands are tabulated below from Table A-21.

Maximum Diversified KW Per WH

Month	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.
Day	Sun.	Sun.	Sat.	Tue.	Sun.	Sun.	Mon.	Sun.	Mon.	Mon.	Sat.	Sun.
Date	13	17	2	9	5	2	22	25	30	21	9	1
Hour Ended (a)	11PM	8 PM	10 AM	11 PM	11 PM	11 PM	8 PM	10 PM	8 AM	9 PM	12 N	12 N
KW	1.7	1.8	1.6	1.5	1.5	1.1	1.0	1.2	1.4	1.4	1.8	1.6

At System Peak Hour - (c)

KW	0.8	0.6	0.4	0.6	0.4	0.5	0.5	0.3	0.5	0.6	0.5	0.6
Day	Thur.	Fri.	Tue.	Mon.	Wed.	Wed.	Tue.	Tue(c)	Thur.	Tue.	Tue.	Mon.
Date	3	1	19	1	29	19	30	20	19	29	19	30
Hour Ended (b)	11 AM	3 PM	5 PM	5 PM	4 PM	4 PM	5 PM	5 PM	5 PM	7 PM	7 PM	7 PM

(a) Times are CDT for January through October and CST for November and December.

(b) Times are CDT for February through September and CST for October through January.

(c) The annual system peak occurred Tuesday, August 20, at 4 to 5 PM.

Houston Lighting and Power Company (Water Heating)
1974 - 1975 AEIC

Month	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.
Avg. Week												
Day KW	1.3	1.2	1.1	1.1	1.0	0.8	0.8	0.3	0.9	1.0	1.1	1.1
Non-Coinc.												
Max. KW	4.3	4.3	4.3	4.2	4.2	4.0	4.0	3.9	3.9	4.0	4.2	4.2
Avg. Monthly												
Temp. °F	54.5	56.5	66.5	67.7	76.5	79.8	81.6	79.7	74.2	69.6	59.8	53.8

4. Based on group maximum diversified demands, the electric water heating has the highest annual load factor (34.3%) of the three major appliances metered (air conditioning, space heating and water heating), but the lowest coincidence factor (40%).
5. Cold water inlet temperatures are not reported.
6. Chart A-26 is attached. This chart shows hourly water heating demands per customer on the day of the system peak (August 20, 1974) and on the days of the summer and winter maximum diversified demands.

CHART A-26

Residential Customer Load Study
Water Heating
Winter and Summer Load Curves - Year 1974
Houston, Texas

RESIDENTIAL ELECTRIC WATER HEATER TEST RESULTS
AS REPORTED BY THE AEIC LOAD RESEARCH COMMITTEE

Long Island Lighting Company

Report Date: 1965 - 1966 (AEIC)

Test Period: March, 1964 through March, 1965

Significant Findings & Comments:

1. This is a study of electric water heaters in single-dwelling homes. Tests were made on two groups of water heaters; one with uncontrolled NEMA heating elements (33 customers), and one with both heating elements controlled so they could operate only between the hours of 10:30 PM and 9:00 AM. The controlled water heaters were further subdivided into two groups: (a) Those with NEMA units (28), and (b) Those with 4.5 KW quick recovery heating units. For the uncontrolled water heaters, the sample included only year-round residences and excluded the following: total-electric homes, homes with central air conditioning, homes with more than two room-type air conditioners. The uncontrolled tests were made from March, 1964 through February, 1965. The test period for the controlled groups was December, 1964 through March, 1965. Inlet and outlet water temperatures were recorded at monthly intervals throughout the test. Water meters were installed in the cold water inlet at 8 locations to meter monthly gallons of hot water use at those locations.
2. The weighted average hot water outlet temperature was 141°F, compared to the average monthly thermostat setting of 146°F.
3. The weighted average water temperature rise for controlled NEMA units was 90°F, and for controlled QR units was 98°F for the three months tested.
4. Seventy-two percent of the daily uncontrolled water heating kilowatt-hours were used during the hours that the controlled water heaters were not permitted to operate.
5. The weekly peaks of the water heaters most frequently occurred as follows:

Uncontrolled NEMA units, on Monday and Saturday (hour not supplied -- except see paragraph #6 below) .
Controlled, NEMA units, on Saturday (hour not supplied).
Uncontrolled Quick Recovery Units, on Wednesday (hour not supplied -- except see paragraph #6 below).
6. For the uncontrolled NEMA units 86% of the maximum coincident demands occurred between the hours ended 11 AM to 2 PM and 7 PM to 9 PM.

Long Island Lighting Company
1965 - 1966 AEIC

7. Correlation between hot water use in gallons per month and energy use per month is given in Chart CW-4.
The equation to fit the chart is:

$$\text{KWH} = 31.5 + .25 \text{ Per Gal.}$$

8. Charts CW-5 and CW-6 which show water heater load curves for selected days are attached.
9. Selected data from Tables CW-6 and CW-7 is tabulated below:

	1964										1964	
	<u>March</u>	<u>April</u>	<u>May</u>	<u>June</u>	<u>July</u>	<u>Aug.</u>	<u>Sept.</u>	<u>Oct.</u>	<u>Nov.</u>	<u>Dec.</u>	<u>Jan.</u>	<u>Feb.</u>
<u>UNCONTROLLED NEMA UNITS (33 Customers)</u>												
Coincident Max. KW (a)												
Per Water Heater	1.08	0.97	0.99	0.97	0.98	1.00	0.89	1.00	0.93	1.04	1.00	0.97
Day & Date	Sat 21	Sun 5	Sat 16	Mon 29	Tue 28	Mon 24	Tue 8	Mon 19	Sat 28	Thu 24	Tue 5	Sat 6
Hour Ended	7 PM	3 PM	8 PM	11 AM	8 PM	1 PM	12 N	11 AM	7 PM	8 PM	11 AM	7 PM
Coinc. Max. KW (a)												
Per WH at System												
Peak	0.73	0.64	0.51	0.49	0.64	0.74	0.70	0.49	0.57	0.60	0.86	0.71
Day & Date	Thu 12	Mon 6	Thu 14	Tue 30	Wed 1	Mon 31	Fri 11	Thu 29	Mon 30	Dec 21	Mon 4	Thu 4
Hour Ended	7 PM	7 PM	6 PM	6 PM	3 PM	9 PM	8 PM	6 PM	6 PM	6 PM	6 PM	7 PM
Non-Coinc. Max. KW Per W. Htr. (a)	1.97	1.91	1.88	1.87	1.81	1.79	1.81	1.87	1.84	1.90	1.93	1.89

(a) 60-minute demand.

Long Island Lighting Company
1965 - 1966 AEIC

YEAR 1964 DATA

	<u>NEMA UNITS</u>			<u>QUICK RECOVERY UNITS</u>		
	<u>Jan.</u>	<u>Feb.</u>	<u>March</u>	<u>Jan.</u>	<u>Feb.</u>	<u>March</u>
<u>CONTROLLED UNITS</u>						
Coinc. Max. KW Per W. Htr. (a)	2.02	2.05	2.04	2.88	2.95	3.01
Day & Date	Wed 6	Sat 13	Sat 20	Fri 15	Wed 3	Mon 29
Hour Ended	12 MN	12 MN	12 MN	1 AM	1 AM	12 MN
Non-Coinc. Max. KW Per Water Heater (a)	2.49	2.51	2.57	3.14	3.12	3.13

(a) 60-minute demand.

CHART CW-5

Residential Electric Water Heating
Daily Load Curves for Uncontrolled NEMA Units
Long Island, New York

CHART CW-6

Residential Electric Water Heating
Daily Load Curves for Controlled Water Heating
Long Island, New York

RESIDENTIAL ELECTRIC WATER HEATER TEST RESULTS
AS REPORTED BY THE AEIC LOAD RESEARCH COMMITTEE

Public Service Electric & Gas Co.

Report Date: 1964 - 1965 (AEIC)

Test Period: Summer, 1963

Winter, 1963 - 1964

Significant Findings & Comments:

1. This is a test of electric water heaters made for a three-week period in the summer months and for a three-week period in the winter months for each method of operation, namely, for:
 - a) Interlocked upper and lower heater elements with time clock on lower element so it could operate only from 11 PM to 9:30 AM.
 - b) Uncontrolled, with an interlock on the heating elements.
 - c) Uncontrolled, without an interlock.Additionally, the test results were further sub-divided into: (a) Standard-type (low wattage) water heaters under 66 gallons; (b) Standard-type (low wattage) water heaters over 65 gallons; and (c) Quick recovery, 4.5 KW heating elements (both upper and lower) with 40 gallon tank size, but uncontrolled.
2. Test results for "under 66 gallons" included from 20 to 24 water heaters. Test results for "over 65 gallons" included from 64 to 73 water heaters. Test results for the "quick recovery" water heaters included from 10 to 14 water heaters.
3. The test results do not provide "demand at time of system peak" for water heaters.
4. Some of the results of the study are:
 - a. With controlled operation, with or without interlock, the greatest demand per water heater for standard-type water heaters occurs in the off-peak hours; usually between midnight and 6 AM, both summer and winter, regardless of tank size. (Charts CRW-1 to CRW-4.)
 - b. With uncontrolled operation, with or without interlock, the greatest coincident demand per water heater for standard-type water heaters usually occurs between 8 AM and 1 PM, both summer and winter, regardless of tank size. However, in the winter, the greatest coincident demand sometimes occurs about 6 PM to 9 PM. (Charts CRW-1 to CRW-4.)

Public Service Electric & Gas Co.
1964 - 1965 AEIC

4. c. The coincident demand of quick recovery water heaters ranged from 1.59 to 3.08 KW. These quick recovery tests may not be representative due to the small number of test water heaters.
- d. There is no significant difference between week day and weekend day maximum demands of water heaters.
5. There is no data showing the water heater demand at the time of system peaks.
6. Charts CRW-1 to CRW-4 inclusive, showing water heater load curves are attached.
7. Some of the test data is summarized in the following tabulations.

	<u>CONTROLLED, WITH INTERLOCK</u>		<u>UNCONTROLLED, WITH INTERLOCK</u>		<u>UNCONTROLLED, NO INTERLOCK</u>	
	<u>Summer</u>	<u>Winter</u>	<u>Summer</u>	<u>Winter</u>	<u>Summer</u>	<u>Winter</u>
	<u>7/7-7/27/63</u>	<u>12/15/63-1/4/64</u>	<u>8/4-8/24/63</u>	<u>1/12-2/1/64</u>	<u>9/1-9/21/63</u>	<u>2/9-2/29/64</u>
<u>UNDER 66 GALLONS</u>						
No. of Customers in Test	23	20	24	24	24	23
Average heater element size:						
Lower element - KW	1.193	1.225	1.177	1.135	1.177	1.141
Upper element - KW	1.568	1.550	1.563	1.542	1.563	1.543
Weekday: Max. Divers.						
KW Per WH	1.19	1.38	0.88	0.96	0.89	1.04
Day & Date	Thur. 7/25	Thur. 12/19	Mon. 8/19	Tue. 1/28	Tue. 9/10	Tue. 2/11
1/2 Hr. Ended	12:30 AM	12:00 MN	11:30 AM	10:00 AM	9:30 AM	12:30 PM
Weekend Day: Max. Divers.						
KW Per WH	1.07	1.34	0.65	0.98	0.89	0.97
Day & Date	Sun. 7/7	Sun. 12/12	Sat. 8/24	Sat. 1/18	Sat. 9/7	Sat. 2/22
1/2 Hr. Ended	12 MN	1:00 AM	10:30 AM	1:00 PM	1:30 PM	1:00 PM

("Under 66 Gallons" concluded on next sheet.)

Public Service Electric & Gas Co.
1964 - 1965 AEIC

	<u>CONTROLLED, WITH INTERLOCK</u>		<u>UNCONTROLLED, WITH INTERLOCK</u>		<u>UNCONTROLLED, NO INTERLOCK</u>	
	Summer <u>7/7-7/27/63</u>	Winter <u>12/15/63-1/4/64</u>	Summer <u>8/4-8/24/63</u>	Winter <u>1/12-2/1/64</u>	Summer <u>9/1-9/21/63</u>	Winter <u>2/9-2/29/64</u>
Non-Coincident Max. KW Per WH(a)	1.83	1.94	1.59	1.73	2.15	2.57
<u>OVER 66 GALLONS</u>						
No. of Customers in Test	64	65	73	64	72	65
Average heater element size: (b)						
Lower element - KW	2.254	2.136	2.212	2.172	2.190	2.181
Upper element - KW	2.175	2.144	2.171	2.148	2.160	2.131
Weekday: Max. Divers.						
KW Per WH	1.94	1.95	1.11	1.11	1.06	1.14
Day & Date	Thur. 7/18	Wed. 1/1	Mon. 8/12	Tue. 1/28	Mon. 9/2	Mon. 2/10
1/2 Hr. Ended	12:30 AM	12:00 MN	11:30 AM	7:00 PM	11:00 AM	11:30 AM
Weekend Day: Max. Divers.						
KW Per WH	1.79	1.94	0.90	1.29	1.20	1.21
Day & Date	Sun. 7/7	Sun. 12/15	Sat. 8/10	Sat. 1/18	Sat. 9/7	Sat. 2/29
1/2 Hr. Ended	12:30 AM	12:00 MN	2:00 PM	7:30 PM	12 Noon	7:00 PM
Non-Coincident Max. Per WH(a)	2.76	2.70	2.67	2.51	2.95	3.14

(a) Average of the individual maximum KW demands in the test period -- on week days.

(b) It appears that the tabulation has the upper and lower heater element wattages reversed.

Public Service Electric & Gas Co.
1964 - 1965 AEIC

	<u>CONTROLLED, WITH INTERLOCK</u>		<u>UNCONTROLLED, WITH INTERLOCK</u>		<u>UNCONTROLLED, NO INTERLOCK</u>	
	Summer	Winter	Summer	Winter	Summer	Winter
	<u>7/7-7/27/63</u>	<u>12/15/63-1/4/64</u>	<u>8/4-8/24/63</u>	<u>1/12-2/1/64</u>	<u>9/1-9/21/63</u>	<u>2/9-2/29/64</u>
QUICK RECOVERY, 4.5 KW ELEMENTS 40 GALLON TANK SIZE						
No. of Customers in Test			14	10	13	11
Average heater element size:						
Lower element - KW			4.500	4.500	4.500	4.500
Upper element - KW			4.500	4.500	4.500	4.500
Weekday: Max. Divers. KW Per WH			1.59	2.59	2.56	3.08
Day & Date			Fri. 8/16	Mon. 1/27	Mon. 9/9	Wed. 2/26
1/2 Hr. Ended			8:30 PM	11:00 AM	11:00 AM	9:00 PM
Weekend Day: Max. Div. KW Per WH			1.41	2.70	2.25	3.01
Day & Date			Sun. 8/18	Sat. 1/25	Sat. 9/21	Sun. 2/16
1/2 Hr. Ended			12:30 AM	1:00 PM	11:30 AM	1:00 PM
Non-Coincident Max. KW Per WH(a)			4.69	4.72	4.91	5.71

(a) Average of the individual maximum KW demands in the test period -- on week days.

CHART CRW-1

Residential Water Heating Load Curves—Average Weekday
Newark, New Jersey

CHART CRW-2

Residential Water Heating Load Curves
Standard Type Water Heaters—Under 66 Gallons
Newark, New Jersey

CHART CRW-3

Residential Water Heating Load Curves Standard Type Water Heaters—Over 65 Gallons Newark, New Jersey

CHART CRW-4

Residential Water Heating Load Curves Quick Recovery Water Heaters Newark, New Jersey

CENTRAL AIR CONDITIONING TESTS

RESIDENTIAL CENTRAL AIR CONDITIONING PEAK LOAD STUDY TEST RESULTS
AS REPORTED BY LOAD RESEARCH COMMITTEE OF AEIC

Arkansas Power & Light Company
(Air Conditioning Controlled Tests)

Report Date: 1975-1976 (AEIC)
Test Period: June 15, 1975 - September 15, 1975

Purpose of Study

The Company's maximum hourly demands in any recent year have occurred during the hottest hours of the day on weekdays during the summer period. This summer peak is primarily caused by air conditioning and it is about 60% higher than the winter peak. The purpose of the test was to determine whether residential summer air conditioning load can be systematically switched off for short time intervals during peak load periods (without undue customer complaint), thereby reducing the peak demand.

Summary of Major Findings

1. In an emergency, as much as 4.17 kW of coincident demand per central air conditioned residence could be dropped during air conditioning peak load conditions as experienced during the test period. (Maximum temperature during the test period were below normal - maximum 93 deg. F.)
2. On September 2, the day of the Company's annual system peak, with each customer's controllable load being switched off from 9 to 13 minutes twice each hour, with a total interruption of 26 to 28 minutes per hour, the average reduction per air conditioner was 1.17 kW on the West Little Rock circuit.
3. Due to indoor temperature increases, it appears that residential air conditioners cannot be interrupted more than 25% of the time.
4. About 79% of the customers responding to a questionnaire felt no house temperature changes after the remote controls were installed. (95% of customers responded.)
5. During the test period of August 22 to September 15, when each unit was being switched off from 26 to 28 minutes each hour of the test hours, the temperature rise in the return air ducts ranged from 4 to 9 deg. F during the switching periods. Catch-up time for air duct temperature ranged from 5 to 7 hours after 5 PM, when switching ceased.
6. All but five of the 218 participants in West Little Rock, following the end of the study in 1975 agreed to allow the Company to leave the controls in place for possible test the next year.

Arkansas Power & Light Company
1975-1976 (AEIC)

Test Method and Incentives to Participants

1. A base (uncontrolled) primary circuit and a test (controlled) primary circuit with approximately the same number of houses served by each were selected at the Little Rock Air Force Base as one test, and in the Colony West-Sturbridge area of West Little Rock as a second test. All four circuits serve only residential load.
2. Radio controls were placed on the compressor and outside fan motor, but not the blower inside the home. Controls were placed at 218 homes on the West Little Rock circuit and on 90 homes on the Little Rock Air Force Base circuit.
3. Air conditioners were controlled as follows:
 - a. Not controlled at any hour other than 1 PM to 5 PM
 - b. Controlled only when outside temperature at Company's control center was 85 deg. F or higher.
 - c. Controls at the homes were sequentially operated so that no customer was interrupted for more than two non-consecutive intervals each clock hour, and for not more than 10 to 28 total minutes each hour.
4. Instrumentation was as follows:
 - a. The four primary circuits were metered with magnetic tape recorders and with chart recorders telemetered by telephone to Company's Little Rock Control Center.
 - b. Twelve controlled air conditioners and twelve uncontrolled air conditioners were equipped with individual magnetic tape recorders.
 - c. Twelve controlled residences were equipped with temperature recorders to monitor return air duct temperature.
 - d. Outside air temperature was continuously recorded at the Company's Little Rock Control Center.
5. Incentives to the customer were:
 - a. \$2 per kva of air conditioning capacity per month during the three-month test period, paid by Company check.
 - b. Free service inspection on the air conditioning system.
 - c. A guarantee that the air conditioning system would be restored to its pre-test condition should any damage result from the test.

Arkansas Power & Light Company
1975-1976 (AEIC)

Discussion of Data

1. Following is data in tabular form for the day on which the peak coincident demand of the two controlled circuits was recorded.

	<u>West Little Rock</u>	<u>L.R. AFB</u>
Number of A/C switched	218	90
Total connected A/C kW @ 95% P.F.	1142	421kW
Average connected kW per A/C	5.24	4.58kW
Day of peak kW drop	Wednesday	Wednesday
Date of peak kW drop	July 9	July 9
Time of peak kW drop	4:00pm	4:00pm
Temperature at peak kW drop	93°F	93°F
Humidity at peak kW drop	51%	51%
Circuit kW before peak drop	1918kW	745kW
Circuit kW after peak drop	1008kW	378kW
Total kW dropped at peak	910kW	367kW
Peak coincident kW drop per A/C	4.17kW	4.08kW

2. Charts C-14, C-16, C-17 and C-18 from the report are attached.

CHART C-14
Average Coincident Load per Air Conditioner vs. Temperature
Little Rock Test Circuit

CHART C-16
Average Coincident Load per Air Conditioner vs. Temperature
Little Rock Air Force Base

CHART C-17
 Little Rock Circuit Load vs. Time of Day
 September 2, 1975

CHART C-18
 Little Rock Circuit Load vs. Time of Day
 September 3, 1975

RESIDENTIAL CENTRAL AIR CONDITIONING TEST RESULTS
AS REPORTED BY THE AEIC LOAD RESEARCH COMMITTEE

Georgia Power Company
(Air Conditioning Controlled)

Report Date: 1975-1976 (AEIC)
Test Period: June - August, 1975
300 Controlled
300 Uncontrolled

Significant Comments & Findings:

1. Tests were made by installing 300 magnetic tape recorders on central air conditioned homes where air conditioning controls were to be installed, and by installing 300 magnetic tape recorders on homes with central air conditioning which was not controlled.
2. At the 300 "controlled" homes, the compressors were shut down for 15 minutes and allowed to run the next 15 minutes. The control was activated when outside temperature of the home reached 88°F at homes north of an east-west line 40 miles south of Atlanta, Georgia, and at 90°F for homes south of that line. The control was deactivated when the outside temperature was below those values.
3. Generally speaking, the control device was activated by 12 noon and deactivated between 7 to 10 PM, although sometimes by 5 PM.
4. On day of annual peak, August 25, 1975, at system peak hour ended 5 PM:

Home Demand -- Non-controlled	5.60* KW	(189 homes with data)
Home Demand -- Controlled	4.20* KW	(149 homes with data)
Reduction attributed to control	1.40* KW	(25% reduction)
5. Range of reduction at 5 PM on August 25, at 95% confidence level = 0.99 KW to 1.81 KW at an accuracy of ± 0.41 kW. (L-176)
6. Tests results were also analyzed for selected "hot" days; i.e., days on which all the controls were activated at all test locations.

Results:

June 18 at hour of system peak: Reduction = 0.93* KW (L-177 & L-189)
 August 16 at hour of system peak: Reduction = 1.11* KW (L-177 & L-189)

7. Tests were analyzed for an "intermediate" day; i.e., a day when most of control devices were activated part of the day, but deactivated "early".
 (Page L-177 & 191)
 On the intermediate day, June 19, the demand at "controlled" homes slightly exceed the "uncontrolled" for all hours except between 3 and 5 PM.
 (page L-184 and L-191).

At the system peak hour for that day, at the hour ended 5 PM, the amount of the excess was 0.02 kW per customer. (ACDC = 3.99 kW; no ACDC = 3.97 kW.)

* All demands are 60-minute KW, clock hour.

Georgia Power Company
1975-1976 AEIC

8. Tests were analyzed for two "cool" days; i.e., days on which none of the controls were activated. The demand per air conditioner at "controlled" homes slightly exceeded the uncontrolled at the hour of system peak on those two days as follows:

July 16, 1975 hour ended 3 PM 2.41* KW no control vs. 2.66* KW
controlled = 0.25* KW (Page L-184)
July 26, 1975 hour ended 4 PM 4:00* KW no control vs. 4.04* KW
controlled = 0.04* KW (Page L-184)
9. It appears that at the "controlled" homes, the residents tended to "pre-cool" the homes in the morning hours, anticipating afternoon controls.
10. Customer acceptance was good based on opinions expressed at interviews in mid-July and at the end of September. Satisfaction with the incentive paid (\$5 per ton of air conditioning) per month and acceptance of the control device averaged 7.2 on a maximum scale of 10. (Page L-180)
11. The air conditioning demand can be expected to be a maximum in the 2 PM to 6 PM period, and usually after 3 PM.
12. Charts C-19 to C-24 inclusive (attached) are graphic charts of demands of test customers with air conditioning demand control (ACDC) compared to test customers without ACDC for specified days and "average" for the week of August 25-31, 1975 (Chart C-20).

* All demands are 60-minute KW, clock hour.

CHART C-19
PEAK DAY COMPARISON
AVERAGE DEMAND FOR TEST RESIDENCES
MONDAY, AUGUST 25, 1975

CHART C-20
 AVERAGE DEMAND FOR TEST RESIDENCES
 WEEK OF AUGUST 25, 1975

CHART C-21
HOT DAY COMPARISON
AVERAGE DEMAND FOR TEST RESIDENCES
WEDNESDAY, JUNE 18, 1975

CHART C-21 (CON'T)
HOT DAY COMPARISON
AVERAGE DEMAND FOR TEST RESIDENCES
SATURDAY, AUGUST 16, 1975

CHART C-22
INTERMEDIATE DAY COMPARISON
AVERAGE DEMAND FOR TEST RESIDENCES
THURSDAY, JUNE 19, 1975

CHART C-23
COOL DAY COMPARISON
AVERAGE DEMAND FOR TEST RESIDENCES
WEDNESDAY, JULY 16, 1975

CHART C-23 (CON'T)
COOL DAY COMPARISON
AVERAGE DEMAND FOR TEST RESIDENCES
SATURDAY, JULY 26, 1975

CHART C-24
PAIRED COMPARISON AVERAGE DIFFERENCE
IN DEMAND FOR TEST RESIDENCES

RESIDENTIAL ELECTRIC CENTRAL SUMMER AIR CONDITIONING TEST RESULTS
AS REPORTED BY THE AEIC LOAD RESEARCH COMMITTEE

Baltimore Gas and Electric Company

Report Date: 1974-1975 (AEIC)

Test Period: 12 months ended April 30, 1974

(Complete data ranged from 27 to 31 customers in the various months.)

Comments and Significant Findings:

1. At 31 homes with central air conditioning magnetic tape DSL & DAL recorders were installed: 1 recorder on total service, 1 recorder on compressor and air circulating fan. (Page L-8)
2. The reported demands of air conditioning is 30-minute, clock 1/2 hour data. (Page L-9)
3. Average cooling connected load is 5.7KW. Loads range from 3.5 KW to 9.1 KW. (Page L-8)
4. The maximum diversified cooling KW demands per customer occurred 3:30 PM and 6 PM in the cooling months of May to October, inclusive. (Page L-7)
5. At the time of the Baltimore annual system peak in the hour ended 4 PM on Thursday, August 30, 1973, 83.7% of the cooling load connected was operating; or, a demand of 83.7% x 5.7 KW, or 4.77 KW per home. (Page L-7)
6. The average of the individual customers' maximum one-hour cooling demands in the test period is 5.31 KW, which is 93.8% of the average cooling connected load. (Page L-17)
7. One-year average of diversified one-hour demands coincident with system peak demands (average of 12 months) is as follows: (Page L-17)

<u>TEST DATA COINCIDENT WITH</u>	<u>COOLING LOAD**</u>	<u>OTHER LOAD**</u>	<u>TOTAL SERVICE**</u>
PJM Peak Hours*	1.59 KW	1.20 KW	2.79 KW
Baltimore System * ("Baltimore Contract" Load)	1.64 KW	1.19 KW	2.83 KW

8. No data relative to KW at time of system peaks is given other than #5 and #7.
9. Charts A-3 through A-9 showing load profiles and diversified average KW demand per customer are attached.
10. See next page.

* Based on other KW values here presented it would appear that the system peaks must usually occur before the cooling load of the test customers reaches a peak.

**These are 60-minute, demands.

10. Test data for the cooling load for each month is tabulated below from Table A-1:
(30-Minute data)

	MAY	JUNE	JULY	AUG. 1973	SEPT	OCT	NOV	DEC	JAN	FEB 1974	MAR	APRIL
Non Coincident Max. 30-Min. KW Avg. Per Cust.	3.50	5.17	5.20	5.25	5.15	2.33	0.56	0.03	0.04	0.06	0.19	2.05
Diversified <u>Maximum KW</u>												
Day	Wed.	Sat.	Sat.	Wed.	Sat.	Thu.	Fri.	Sat.	Tue.	Fri.	Thu.	Tue.
Date	30	9	7	29	1	4	23	1	1	1	7	30
1/2 Hr. Ended	6P	6P	5:30P	4:30P	4P	5:30P	8:30P	1A	12:30A	8:30P	5:30P	4:30P
KW Per Customer	2.27	4.38	4.54	4.89	4.68	1.65	0.24	0.02	0.03	0.03	0.17	1.23
Mean Temperature °F on Date of Cooling Maximum Diversified KW Per Customer	70	81	77	85	83	71	51	41	39	38	58	73

Baltimore Gas and Electric Company
1974-1975 AEIC

CHART A-3

Total-Service and Central Air Conditioning Load Curves

Day of Maximum Diversified Total-Service Demand

12 Months Ended April 30, 1974

Baltimore, Maryland

CHART A-4

Total-Service and Central Air Conditioning Loads
on Day of Maximum Diversified Total-Service Demand in Each Summer Month
12 Months Ended April 30, 1974
Baltimore, Maryland

CHART A-5

System Total-Service and Central Air Conditioning Hourly Loads

Day of Baltimore Contract Load Annual Peak

12 Months Ended April 30, 1974

Baltimore, Maryland

CHART A-6

System, Total-Service and Central Air Conditioning Hourly Loads

Day of Maximum Cooling Degree-Days (65°F Base)

12 Months Ended April 30, 1974

Baltimore, Maryland

CHART A-7

Relationship of Central Air Conditioning Daily Cooling Use

Per Customer to Daily Cooling Degree-Days (65°F Base)

12 Months Ended April 30, 1974

Baltimore, Maryland

CHART A-8

Relationship of Central Air Conditioning Daily Maximum Diversified Half-Hour Cooling Demand

Per Customer to Daily Cooling Degree-Days (65°F Base)

12 Months Ended April 30, 1974

Baltimore, Maryland

CHART A-9

Relationship of Central Air Conditioning Daily Maximum Diversified Half-Hour Cooling Demand

Per Customer to Daily Cooling Use Per Customer

12 Months Ended April 30, 1974

Baltimore, Maryland

RESIDENTIAL ELECTRIC HEAT PUMP (CENTRAL AIR CONDITIONING) TEST RESULTS
AS REPORTED BY THE AEIC LOAD RESEARCH COMMITTEE

Baltimore Gas and Electric Company

Report Date: 1971-1972 (AEIC)

Test Period: 12 Months ended December 31, 1969

("Complete" data ranged from 28 to 31 customers.)

Comments and Significant Findings:

1. At 31 test homes (out of about 200 population) three Westinghouse DAL recorders were installed: 1 to record total home; 1 to record heat pump with its supplementary resistance and circulating air fan; 1 to record only the supplementary resistance plus the air circulating fan. (Page L-126)
2. The reported demands of air conditioning (and heating) in the tables are on clock half-hour basis (30-minute demands).
3. The average cooling connected load per customer is 4.998 KW, and in the hour when the cooling load was greatest in the Baltimore system during a peak hour (hour ended 3 PM on Thursday, July 17, 1969) the cooling load was 40.5% of the average connected cooling load, or $.405 \times 4.963$, or 2.01 KW per customer. (Page L-125)
4. The 2.01 KW at July system peak compares to a maximum 30-minute KW of cooling load of 2.35 KW on Thursday, July 17 at 1/2 hour ended at 6 PM. (Table CHA-1)
5. The highest 30-minute cooling KW per customer (diversified maximum) was 2.78 KW, on Saturday, June 28 at the 1/2 hour ended at 5:30 PM. (Table CHA-1).
6. Each heat pump cooling unit adds 0.62 KW to the Baltimore system monthly peak hours, averaged over a 12-month period. (Page L-125)
7. One-year average diversified demands coincident with system peak hour.

<u>TEST DATA COINCIDENT WITH</u>	<u>COOLING LOAD KW*</u>	<u>HEATING LOAD KW*</u>	<u>TOTAL RESIDENCE SERVICE KW*</u>
PJM Peak Hours	0.65	1.46	3.76
Baltimore System Peak Hours ("Baltimore Contract" Load)	0.62	1.50	4.01

*It appears, from the tabulation and discussion on Page L-143, that the KW tabulated is 1-hour data.

Baltimore Gas and Electric Company
1971-1972 (AEIC)

8. Cooling 1-hour demands, calculated from a table on Page L-143, and calculated from connected load data of Table CHA-1, at the Baltimore system peak hour are as follows:

Date & Hour Ended	May 29	June 30	July 17	Aug. 25	Sept. 2	Oct.
	3 PM	4 PM	3 PM	5 PM	2 PM	
Connected KW Per Customer	4.988	4.988	4.963	4.988	4.988	
% of Connected KW on Peak	12.8%	37.7%	40.5%	36.5%	21.3%	
1-Hour Cooling KW on Peak	0.638	1.880	2.010	1.821	1.062	

9. Non-Coincident Max. 30- Min.
KW Per Cust. (Avg. Per Cust.)
	3.68	4.50	4.39	4.33	4.16	1.64

10. Diversified Max. 30-Min. KW per Cust.

KW	2.00	2.78	2.35	2.46	2.31	0.62
Day & Date	Thu. 29	Sat. 28	Thu. 17	Mon. 25	Mon. 1	Fri. 3
1/2 Hour Ended	6:30 PM	5:30 PM	6 PM	5:30 PM	6 PM	7 PM
Mean Temp. °F, on that day	82	86	85	81	82	76

11. Charts CHA-1, CHA-3, CHA-4, CHA-6, and CHA-7 are attached.

Load Research

CHART CHA-1
 Total-Service and Heat Pump Load Curves
 Day of Maximum Diversified Total-Service Demand
 12 Months Ended December 31, 1969
 Baltimore, Maryland

Load Research

CHART CHA-3
 Total-Service and Heat Pump Loads
 Days of Maximum Diversified Total-Service Demand
 12 Months Ended December 31, 1969
 Baltimore, Maryland

Load Research

CHART CHA-4
Total-Service and Heat Pump Loads
Days of Maximum Diversified Total-Service Demand
12 Months Ended December 31, 1969
Baltimore, Maryland .

CHART CHA-6

System, Total-Service and Heat Pump Hourly Loads
 Day of Baltimore Contract Load Annual Peak
 12 Months Ended December 31, 1969
 Baltimore, Maryland

CHART CHA-7

Total-Service and Heat Pump Load Curves
 Day of Maximum Diversified Total-Service Summer Demand
 12 Months Ended December 31, 1969
 Baltimore, Maryland

RESIDENTIAL ELECTRIC FURNACES & CENTRAL AIR CONDITIONING TEST RESULTS
AS REPORTED BY THE AEIC LOAD RESEARCH COMMITTEE

Baltimore Gas and Electric Company

Report Date: 1970-1971 (AEIC)

Test Period: 12 months ended April 30, 1970

Comments and Significant Findings:

1. This was primarily a test of 19 single family residences equipped with electric furnaces. Of the 19, fourteen also had central cooling systems. For the cooling portion of the tests, Westinghouse Type DAL magnetic tape load survey recorders were used to record the cooling use (Page L-194)
2. The average connected cooling load was 6.34 KW. It ranged from 5.2 to 8.5 KW.
3. The maximum diversified cooling demand occurred in the 1/2 hour ended 6 PM on Saturday, July 26, and was 4.13 KW. In all other cooling months the maximum diversified cooling demand occurred between 3 and 5 PM. (Page L-208)
4. A graphic load plot is presented for cooling only on the day of maximum cooling KWH consumption, for Sunday, September 7, 1969 (Chart CA-1). Outdoor temperature reached a maximum of 90° F (Chart CA-1).
5. The one-year average central cooling one-hour demand coincident with the Baltimore system monthly peak hour is 17.8% of the cooling connected load, or $.1789 \times 6.3 \text{ KW} = 1.13 \text{ KW}$. (Pages L-193 & L-213)
6. The test summer was somewhat hotter than normal -- 1,515 DD vs. 1,384 normal. The annual use of the cooling connected load was 417 hours (2,640 KWH), or it would be 392 hours on a normalized basis. (Page L-193)
7. One-hour average diversified demands per customer, coincident with the system peak, is tabulated below (cooling load KW), as derived from data on page L-213 and from Table CA-1.

	<u>MAY</u>	<u>JUNE</u>	<u>JULY</u>	<u>AUGUST</u>	<u>SEPTEMBER</u>	<u>OCTOBER</u>
Date and Hour Ended	3PM	4PM	3PM	5PM	2PM	7PM
Connected KW Per Customer						
(Cooling KW)	6.390	6.304	6.304	6.362	6.405	6.405
% of Connected KW on Peak	21.1%	53.8%	44.6%	55.5%	36.7%	0.3%
1-Hour KW Per Customer on System						
Peak	1.35	3.39	2.81	3.53	2.35	0.019

Baltimore Gas and Electric Company
1970-1971 (AEIC)

	<u>MAY</u>	<u>JUNE</u>	<u>JULY</u>	<u>AUGUST</u>	<u>SEPTEMBER</u>	<u>OCTOBER</u>
8. Non Coincident Max. 30 Min. KW Per Cust. (Avg.)	3.50	5.14	5.53	5.07	5.27	1.67
9. Diversified Max. 30 Min. KW <u>Per Customer</u>						
KW	2.00	3.56	4.13	4.00	3.90	1.01
Day & Date	Thur. 29	Mon. 30	Sat. 26	Fri. 1	Sun. 7	Fri. 3
1/2 Hour Ended	5 PM	3:30 PM	6 PM	4 PM	4 PM	4 PM
Temperature on date of diversified maximum						
Max. °F	97	94	80	82	89	80
Mean °F	82	82	79	79	80	76
10. The entire report is attached, pages L-191 -- L-229.						
11. Charts CA-1 through CA-3 are attached.						

Load Research

CHART CA-1
Central Cooling Load Curve
Day of Maximum Cooling Use
12 Months Ended April 30, 1970
Baltimore, Maryland

CHART CA-2

Relationship of Daily Central Cooling Use
Per Customer to Daily Degree-Days on Two Bases
12 Months Ended April 30, 1970
Baltimore, Maryland

CHART CA-3

Relationship of Daily Half-Hour Maximum Diversified
Central Cooling Demand Per Customer to Daily Degree-Days
on Two Bases
12 Months Ended April 30, 1970
Baltimore, Maryland

RESIDENTIAL ELECTRIC CENTRAL SUMMER AIR CONDITIONING TEST RESULTS
AS REPORTED BY THE AEIC LOAD RESEARCH COMMITTEE

Baltimore Gas and Electric Company

Report Date: 1965 - 1966 (AEIC)
Test Period: 12 Mo. Ended October 31, 1964
Time Interval: Some 30-minute
Some 60-minute

Comments and Significant Findings:

1. This is a test of 33 residences where central air conditioners are in use. Magnetic tape recorders were used (2 at each home) to meter: (a) Total residence, and (b) The compressor cooling unit -- separately.
2. The average capacity of the cooling units is 39,133 Btu per hour. The average floor space is about 2,050 sq. ft. The maximum demand (30-minute) of any cooling unit was 7.7 KW.
3. The maximum diversified demand per customer, for cooling, was 4.3 KW in June (30-minute KW). This occurred at 6:30 PM on Wednesday, June 10, 1964.
4. At the hour of the system annual peak (September 11, 1964, hour ended 2 PM) the air conditioning demand (60-minute) was 3.5 KW, which is 66% of the cooling connected load. (Page L-66)
5. The summer test period was cooler than normal. (1,273 vs. 1,452 degree days, or 12.3% lower.) See page L-69.
6. One-year average of diversified one-hour demands coincident with the system peak hour demands (average of 12 months) is as follows:

TEST DATA COINCIDENT WITH	COOLING LOAD	OTHER LOAD	TOTAL SERVICE
PJM Peak Hours	1.1 KW	1.2 KW	2.3 KW
Baltimore System	1.2 KW	1.3 KW	2.5 KW
Primary Distribution System Peak Hours on Days of System Peak	1.2 KW	1.4 KW	2.6 KW

7. Cooling 1-hour demands, calculated from a table on page L-76 and from Table A-10 data, at the Baltimore system peak hour are as follows:

Month	MAY	JUNE	JULY	AUGUST	SEPT.
Date & Hour Ended	19 3 PM	22 2 PM	1 2 PM	31 4 PM	11 2 PM
Connected KW Per Customer	5.4	5.4	5.3	5.4	5.3
% of Air C. KW on Peak	16.7%	55.6%	60.4%	61.1%	66.0%
1-Hr. Cooling KW on Peak	0.90	3.00	3.20	3.30	3.50

Baltimore Gas and Electric Company
1965 - 1966 AEIC

	<u>MAY</u>	<u>JUNE</u>	<u>JULY</u>	<u>AUGUST</u>	<u>SEPT.</u>
8. Cooling Non-Coincident Max. 30-Minute KW Per Customer	4.40	5.10	5.00	5.00	4.80
9. Cooling Diversified Max. <u>30-Min. KW Per Customer</u>					
KW	3.10	4.30	4.30	3.80	4.20
Day and Date	Sat. 23	Wed. 10	Sun. 19	Mon. 31	Fri. 11
1/2 Hour Ended	6 PM	6:30 PM	7:30 PM	7 PM	7 PM
°F Temp. Max. on That Day	89	92	86	79	89
Mean for Month	78	80	82	82	84

10. Charts A-14 to A-18, inclusive, (attached) show load curves under various conditions. The attached Charts A-19 and A-20 are graphic presentation of daily kilowatt-hour use per customer, related to cooling degree-days.

CHART A-14
Load Curves
Total Service—Air Conditioning
Day of Maximum Total Service Demand
Wednesday, June 10, 1964
Baltimore, Maryland

CHART A-15

Lead Curves
Total Service—Air Conditioning
Day of System Peak
Friday, September 11, 1964
Baltimore, Maryland

CHART A-16

Load Curves
Total Service—Air Conditioning
Each Summer Month Peak Day, 1964
Baltimore, Maryland

CHART A-17

Load Curves
Total Service—Air Conditioning
Each Summer Month Average Weekday, 1964
Baltimore, Maryland

CHART A-18

Load Curves
Total Service Load—System Load
On Day of Most Cooling Degree-Days
Baltimore, Maryland

CHART A-19
Relationship of
Daily Cooling Use to Daily Cooling Degree-Days
Each Summer Month, 1964
Baltimore, Maryland

CHART A-20
Relationship of
Daily Cooling Use to Daily Cooling Degree-Days
All Days of Summer, 1964
Baltimore, Maryland

RESIDENTIAL CENTRAL AIR CONDITIONING TEST RESULTS
AS REPORTED BY THE AEIC LOAD RESEARCH COMMITTEE

Consumers Power Company

Report Date: 1964 - 1965 (AEIC)
Test Period: May 1 - September 30, 1960
Time Interval: 30-Minute

Comments and Significant Findings:

1. This is a test of 39 customers in the Southern Michigan area of Consumers Power Company. Punched tape recorders (digital) were used. One recorder was for total load, the other recorder was on the air conditioner load. Data was complete for 33 customers for the entire period.
2. The average home contained 1,879 square feet of living area. The average air conditioner was rated 3.43 tons.
3. The maximum half-hour diversified demand was 3.29 KW per customer on Thursday, September 1, at the half-hour ended at 2:30 PM.
4. The maximum average weekday diversified demand was 2.37 KW at 4:30 PM for September 5 through September 9.
5. The maximum non-coincident demand per customer was 4.43 KW.
6. The air conditioning normally peaks between 4 PM and 7 PM.
7. The peak hourly demand for Consumers Power Company during the test period occurred on August 29 between 11 AM and 12 noon. The air conditioning for that hour was 1.62 KW per customer.
8. There is no data regarding contribution to system peak other than #7 above and graphic representation of Chart A-5.
9. Demand data selected from Table A-4 is tabulated below.

	<u>MAY</u>	<u>JUNE</u>	<u>JULY</u>	<u>AUG.</u>	<u>SEPT.</u>
Maximum diversified KW					
Per Customer	0.75	1.61	3.04	3.06	3.29
Avg. of individual Max.					
Non-Coinc. KW	1.48	2.90	4.15	4.06	4.24
Max. Average Weekday					
Diversified Demand In KW	0.30	1.18	2.31	1.62	2.37

10. Charts A-4 to A-8, inclusive, are attached.

CHART A-4

Demand and Temperature Curves
Week of Maximum Central Air Conditioning Use, 1960
Southern Michigan

CHART A-5

Central Air Conditioning Load Curves
Southern Michigan

CHART A-6

Total Residence and Central Air Conditioning Load Curves
Maximum Average Weekday, September 5-11, 1960
Southern Michigan

CHART A-7

Central Air Conditioning Load and Temperature Curves
Hottest Day of Test Period, September 8, 1960
Southern Michigan

CHART A-8

Total Residence and Central Air Conditioning Load Curves
Average July Weekday
Southern Michigan

RESIDENTIAL CENTRAL AIR CONDITIONING TEST RESULTS
AS REPORTED BY THE AEIC LOAD RESEARCH COMMITTEE

Detroit Edison Company

Report Date: 1966 - 1967

Test Period: June - September, 1965

Time Interval: 30-Minute

Comments and Significant Findings:

1. This is a test of the central air conditioning (cooling) units in 30 employee's homes, covering the period of June - September inclusive, in 1965.
2. For the 30 customers: Average cooling rated capacity 2.53 tons
 Average square feet of home 1,295
3. Cooling degrees in the test period were 639 compared to 750 "normal".
4. Based on a 2 PM system peak, the 60-minute KW added, per test customer is 2.26 KW. (No date or day given.) Note: This seem high -- see #5 below.
5. The diversified maximum demand per customer was 2.85 KW from 4:00 to 4:30 PM and at 6 PM.
6. The load curve for Saturday, August 14 is shown in Chart CA-1, page L-163.
7. It appears that the air conditioning load reaches a maximum on most days (or perhaps all days) after 3 PM.

RESIDENTIAL CENTRAL AIR CONDITIONING TEST RESULTS
AS REPORTED BY THE AEIC LOAD RESEARCH COMMITTEE

The Hartford Electric Light Company

Report Date: 1964 - 1965
Test Period: 12 months ended May 31, 1964
Time Interval: 30 Minute

Comments and Significant Findings:

1. This is a test of 33 "Gold Medallion" all-electric homes, with heat pumps for heating and cooling. The homes are in a single development in Stamford, Connecticut. At each home one magnetic tape recorder was installed on the total home and another was installed on the heat pump. One recording thermometer was installed to record outdoor temperature. The degree days tabulated are the difference between 65°F and the average of the 24 hourly temperatures each day. The number of "good" tapes (tests) ranged from 25 to 31.
2. The approximate average square feet of area of the homes was 1,250. The range was from 1,200 minimum to 1,325 maximum.
3. The heat pump average KW demand per customer, at the time of the system peak ranged from 0.11 KW to 2.5 KW in the summer months of May to September, inclusive.
4. The maximum diversified demand of the heat pump ranged from 1.8 KW to 3.0 KW in the summer months of May through September. (Table A-21)
5. At the time of the summer months system peak, at the hour ended at 12 noon on June 28, the heat pump diversified demand was 1.8 KW per customer. (Table A-21)
6. On the day of the summer system peak, on June 28, the diversified maximum demand of the heat pumps occurred during the period of about 3:30 PM to 6:00 PM. (Chart A-25). The maximum value was 2.6 KW for the half-hour ended at 3:30 PM. (Table A-21)

The Hartford Electric Light Company
1964 - 1965 AEIC

7. Demand data for the heat pump for the months of May to September, inclusive, selected from Table A-21 is shown below.

	<u>1964</u>	<u>1963</u>			
	<u>MAY</u>	<u>JUNE</u>	<u>JULY</u>	<u>AUGUST</u>	<u>SEPT.</u>
Maximum Diversified KW					
Demand Per Customer					
KW	3.2**	2.6	3.0	1.8	3.0**
Day and Date	4	Fri. 28	Mon. 1	Thu. 8	Wed. 25
1/2 Hour Ended	6 AM	3:30 PM	5 PM	6 PM	7 AM
Average Demand Per Customer					
at Hour of System Peak					
KW*	0.27	1.8	2.5	1.4	0.11
Day and Date	Mon. 25	Fri. 28	Fri. 26	Fri. 23	Wed. 4
System Peak Hour Ended					
At	11 AM	12 N	2 PM	2 PM	12 N
Temperature, °F, at Time of					
Maximum Diversified Demand	35	94	97	71	53

* Presumed to be 30-minute maximum KW at one of the two half-hours of the system peak hour.

** Probably heating -- not cooling.

RESIDENTIAL CENTRAL AIR CONDITIONING TEST RESULTS
AS REPORTED BY THE AEIC LOAD RESEARCH COMMITTEE

Houston Lighting and Power Company

Report date: 1974-1975

Test Period: 12 months of 1974

(51 All-Electric Homes) HOURLY DEMANDS

Comments and Significant Findings:

1. At 42 of 61 all-electric home test locations the air conditioning unit was recorded on a separate track of the magnetic tape recorder, except that at 35 of the 42, the air handling blower is on the "heating" data track and appears as "heating" in the summer months.
2. The maximum non-coincident demand of the individual air conditioning units ranges from one-hour demands of 2.8 KW to 6.1 KW with an average of 4.9 KW. (Table A-15)
3. The square footage of the homes ranges from 968 to 2,126 sq. ft. with an average of 1,561.
4. One-hour demands of the control air conditioning unit are tabulated below from Table A-19.

Maximum Diversified KW Per Home

Month	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept.	Oct.	Nov.	Dec.
Day	Thur.	Sat.	Sun.	Wed.	Sun.	Sun.	Sun.	Mon.	Mon.	Thur.	Sun.	Tue.
Date	17	2	31	3	29	23	28	19	2	10	3	24
Hour Ended	8 PM	6 PM	6 PM	6 PM	6 PM	6 PM	5 PM	5 PM	4 PM	5 PM	4 PM	5 PM
KW	0.6	1.0	2.3	2.7	3.9	4.3	4.4	4.5	4.1	3.0	2.1	0.8

At System Peak Hour*

KW	0.0	0.5	1.7	2.4	3.8	3.7	4.1	4.1	3.9	1.9	1.3	0.5
Day	Thur.	Fri.	Tue.	Mon.	Wed.	Wed.	Tue.	Tue.*	Thur.	Tue.	Tue.	Mon.
Date	3	1	19	1	29	19	30	20	19	29	19	30
Hour Ended	11 AM	3 PM	5 PM	5 PM	4 PM	4 PM	5 PM	5 PM	5 PM	7 PM	7 PM	7 PM

* The annual system peak occurred Tuesday, August 20 at hour ended 5 PM.

Houston Lighting and Power Company
1974-1975 AEIC

At System Peak Hour - Cont'd.

Avg. Week												
Day KW	0.2	0.2	0.9	1.3	2.9	3.4	3.6	3.4	2.0	1.5	0.3	0.2
Non-Coinc.												
Max. KW	2.1	2.4	3.9	4.4	4.6	4.7	4.1	4.7	4.6	4.1	3.2	2.6
Avg. Monthly												
Temp. of	54.5	56.5	66.5	67.7	75.5	79.8	81.6	79.7	74.2	69.6	59.8	53.8

5. The maximum diversified demand always occurred at the hour ended 4 PM, or later.

RESIDENTIAL CENTRAL AIR CONDITIONING TEST RESULTS
AS REPORTED BY THE AEIC LOAD RESEARCH COMMITTEE

Long Island Lighting Company

Report Date: 1969-1970
Test Period: June - Sept. 1969
Time Interval: 60-minute for all data

Comments and Significant Findings:

1. This is a report on tests of 16 single-dwelling homes with central air conditioning. It covers the period of June to September, inclusive in 1969. The cooling degree days was 1,175 compared to "normal" of 1,107 for that period of months. Two Westinghouse Type ASL or DAL, magnetic tape recorders were installed at each home: 1 recorder for total load; 1 recorder for cooling load.
2. The cooling load demands coincident and non-coincident with the system peak were respectively 0.88 KW per ton and 1.35KW per ton (per ton of cooling capacity). KW is on 60-minute basis.
3. The charts on page L-137 show that for most of the time the peak hour of use of cooling load is not coincident with the hour of the system peak.
4. KW demand at time of system peak hour is shown only for the one month when the annual system peak occurred. The data is tabulated below.

Maximum diversified cooling load KW per customer during the test period (Friday, August 8, 1969 at the hour ended at 3 PM).	3.91 KW
Cooling load per customer <u>at time of yearly system peak</u> at the hour ended at 3 PM on Thursday, July 17, 1969.	3.36 KW
Maximum non-coincident demand in any month in the cooling season (Average of individual customers' maximums in the month).	5.14 KW*

5. The average rated tons of cooling capacity per customer is 3.813 tons.

* It is not clear whether this represents the demands of a single month, or whether it represents the entire test cooling season of June - September, 1969. (See Table CA-2, Line 12.)

RESIDENTIAL CENTRAL AIR CONDITIONING TEST RESULTS
AS REPORTED BY THE AEIC LOAD RESEARCH COMMITTEE

Pacific Gas and Electric Company

Report Date: 1965 - 1966
Test Period: May 6 - October 24, 1964
Time Interval: Not stated
Assume it is 30-minute

Comments and Significant Findings:

1. This is a test of 12 central air conditioning units in residences at Fresno, California. Due to loss of data, only 9 units' data is included. (There were also separate tests of room coolers, not here discussed. Air conditioning is not generally installed in this service area.)
2. The maximum diversified demand per customer was 3.53 KW at 5 PM on July 25.
3. The maximum non-coincident demands were not much greater. (See tabulation below.)
4. No data is supplied regarding contribution of the load to system peak.
5. Demand data (presumed to be 30-minute) is tabulated below from Table CA-1.

	MAY 6 TO <u>JUNE 3</u>	JUNE 3 TO <u>JULY 1</u>	JULY 1 TO <u>JULY 28</u>	JULY 28 TO <u>AUG. 26</u>	AUG. 26 TO <u>SEPT. 23</u>	SEPT. 28 TO <u>OCT. 21</u>
Maximum Diver- sified Demand Per Customer:						
KW	2.37	3.37	3.53	3.46	2.77	2.41
Date	5/12	6/26	7/25	8/7	9/12	10/12
Non-Coincident Max. KW Per Cust. (Avg. of The Max. Per Cust.)	2.98	3.64	3.65	3.58	3.48	3.46

APPENDIX C

Self-Contained Load Control and Load Limiting Devices

No discussion of equipment and technology for the control of end use customers load would be complete without reference to the many forms of control devices which are designed for installation at the customers' location and which are, to all intents and purposes, self-contained. These systems are technically self-contained, although some may utilize an input from the utility in some form such as a time sequence, salient points of utility load profile, or command signal as will be elaborated upon later, as appropriate to the device under consideration. The device is characterized by the common factors of all logic, sequencing functions and equipment are contained within a unit which is independent and unique to an individual customer. The importance of the inclusion of these devices in this study is to ensure familiarity with the technology so that the uses and limitations with respect to utility benefits are appreciated and that such equipment is recognized as being distinct from control systems employing direct utility control.

Devices within this category range from the simplest time switch control for use with a residential water heater to a complex programmable mini-computer capable of the complete energy management function for a large industrial complex. These devices have been segregated by function in this section and described for method of operation, use, application to the utility system and compatability with direct load control objectives. Devices covered are:

1. Time switches
2. Modified Time Switches
3. Auctioneering load limiters
4. Preprogrammed (fixed) demand limiter
5. Programmable load limiters and energy management systems.

1. Time Switch Control

1.1 Operation

This device is characterized by the ability to control, on a preset time sequence, related to real time. No other input information is available. Control of end-use customer appliances by means of a preset time sequence has been applied for many years and it is probably the oldest form of customer load control imposed by a utility. In its simplest and original form, the time switch contained an electrically wound spring, a mechanical clockwork escapement and a single on/off contact function per dial revolution (24 hours). The controlled appliance was invariably the electric water heater and the control sequence was a fixed

time period, seven days a week, all year. The advent of frequency-controlled power generation led to the use of synchronous time switch drives. Further developments included multiple switching, day-omitting devices and the restoration of the electrically wound spring to provide a reserve function to overcome the resetting problems inherent with purely synchronous drives. The present day mechanical time switch is an inexpensive and versatile device which may be utilized to provide control.

Developments within the present state of the art include the use of solid state logic devices capable of clock/calendar functions and permitting virtually day-by-day programming of any required on/off cycles. This permits an extension of the day-omitting function to exclude holidays or other days which can be predesignated as "non-control" days. The use of low current, low voltage logic permits the application of small, float-charged batteries for carryover in the event of loss of power. It should be noted that the time keeping accuracy obtainable with these latter switches is far in excess of that available with mechanically-driven equipment.

1.2 Use

Time switch control of a load results in regular and long interruptions of that load for peak load control purposes. Due to the relatively few on/off functions available, the difficulty in ensuring accurate time and the expense of resetting the switches twice a year to compensate for daylight saving time, the total "off" time must be relatively long in order to span the time where peak control is desired. These long interruptions dictate that the end use appliance must have an adequate storage capacity to bridge this gap if the customer is not to be aggravated to the point where he may defeat or remove the device. This consideration has restricted the use of time switches to water heater control almost exclusively up to this time, although other possible uses are in connection with refractory brick or oil heat storage systems. In normal applications, only one load is controlled from each time switch. Provision of two pole contacts would permit the control of two devices but on the same time sequence.

1.3 Application to a Utility System

The application of time switches to a utility network involves few considerations. Each unit is entirely unrelated to any other and switches may be added, removed or the sequence modified on a customer by customer basis as required. Minor areas which may deserve attention in specific applications would be items such as reserve drives for locations with a history of power interruptions and the use of mechanical escapements in place of synchronous drives for areas without frequency controlled power systems (most commonly off shore applications).

The largest influence in the use of time switches is in the logistics of maintaining accurate time keeping and achieving control at the most advantageous time. Routine time checks and the resetting of errant units may be made by meter reading personnel with a small but nevertheless measurable impact upon their normal work load or schedule, but any major resetting tasks such as the change to and from daylight saving time will cause a significant disturbance in normal work routines.

1.4 Compatibility With Load Control Objectives

Time switches effectively do limit the kW demand of the controlled customer and thereby the total demand of the system, but such results are not achieved without penalties. No control philosophy other than fixed on/off daily control is possible and as previously noted, the duration of the "off" period must be relatively long in order to ensure coverage of the system peak. In addition, control is exercised whether peak load limitation is required on that day or not and this will result in some loss of kWh revenue. Some increase in customer dissatisfaction is to be expected which will be reflected in increased customer service costs. Any change required in the control timing will also increase costs as such changes can only be effected by personnel visits to each time switch installation.

Avoidance of a secondary system peak following a period of control is inherent with the use of time switches due to the characteristics of the switch time setting, such as non-precision levers and small scale lengths per hour for clock setting. The combination of these two factors creates a random restoration pattern even though many switches are set at the same nominal time.

2. Modified Time Switch Control

2.1 Operation

A variation of the simple time related control is available in which the time switch is coupled to an outside thermometer to give better intelligence. Two basic forms are common.

One comprises a seven-day time switch monitored by the outside thermometer. The time switch is set to correspond to the days and times of the predicted system peak and the temperature element set to operate at the ambient temperature which past records show to be peak related. Thus the time switch controls the day (the actual time is not critical) and the outside thermometer monitors the air temperature. Should either condition occur without the second, no action is initiated. When both of the conditions are satisfied, indicating a high probability of a system peak, control is commenced. The device may either disconnect the controlled load or introduce a timed sequence consisting of a preset percentage of a timed period; e.g., 15 minutes per hour. The seven-day time switch prevents unnecessary control over the weekend periods.

The second variation, suitable for heating and cooling loads, consists of either a twenty-four hour or seven-day programming time switch working in conjunction with a controllable time sequencer. The sequencer function is governed by an outdoor thermometer such that during any desired control period, the on/off ratio of the sequencer changes with outside temperature variation to minimize customer discomfort. The time switch, which controls the sequencer operation, may be preset to introduce a limiting action at a time coincident with the system anticipated peaks, but is unable to distinguish between days of normal peaks and the days of maximum peaks.

2.2 Use

Addition of the outside thermometer to time switch control removes the requirement that the load is shed regularly, regardless of the system requirements. At least, the control may be restricted to those periods which, from past history, are known to correspond with certain temperature extremes. Those devices using sequencers to limit the "on" time follow roughly the same uses as those above but are applicable to loads without the storage characteristics necessary for simple on/off controls.

2.3 Application to a Utility System

For all practical purposes, the application consideration for temperature controlled time switches are very similar to those for simple time switches, with the exception that the monitoring action of the thermometer avoids the need for accurate timekeeping. While the non-precision nature of the sensors will do a creditable job in preventing a coincident load restoration problem at the end of a control period, one additional fact must be considered.

Temperature sensitive controls may create secondary peaks of high magnitude if an area is subjected to a sudden change in ambient conditions as would be typical in the event of thunderstorm activity following a prolonged hot period. While such events may coincide with the system peaks, the effects could seriously jeopardize the security of the distribution system by destroying the diversity assumed in the system design.

2.4 Compatibility With Load Control Objectives

The use of temperature controlled time switches, like simple time switches, do limit the kW demand of the controlled customer and the system but with some of the less desirable features removed. The total control period is less as the accuracy of the time switch setting is no longer the sole consideration and this can be a major factor in customer acceptance. The disadvantage in requiring a visit to each customer's location for the purpose of control changes remains common to both simple and temperature controlled time switches. Restoration of load following an "off"

period would have a minimum impact on the system due to the individual nature of the control with the possible exception of a sudden temperature change referred to earlier.

Devices using a variable sequencer for control, rather than an "on/off" command are inherently less amenable for use as a peak load limiter. The very nature of the device in preserving the customer's comfort means that as the temperature extremes are approached, the ratio of the "on time" to "off time" increases and the diversity decreases. Taken on a system-wide basis, the net result is an increase in kW as the temperature extremes are approached - a direct reversal of the action required for peak load control. This equipment is more suitable for limiting customer kWh usage over an extended period (in minimizing unnecessary use of equipment) than for limiting kW demand on peak days.

3.0 Auctioneering Load Limiter

3.1 Operation

This load limiter is a device which senses the use of two or more appliances and disconnects one or more of these loads on a preset priority basis. Such a device may, for example, sense the use of an electric range and disconnect a water heater whenever the range is in use. The kW demand of the customer is therefore reduced in that the combined demands of the appliances connected to the load limiter are prohibited. Exhibit C-1 shows a functional diagram for an example of the application to three appliances.

3.2 Use

Utilization of a load limiter prevents the simultaneous use of different appliances but certain precautions must be observed in the selection of the order of priority if the device is to be acceptable. Generally speaking, devices with storage facilities or non-continuous cycles must be relegated to the lowest category. In an average household, such devices would be water heaters or large freezers. Appliances such as electric stoves which rely on a time/temperature relationship for correct operation must be given the greatest priority. Between these two extremes are difficult areas such as clothes dryers, clothes washers and dishwashers. While these may be interrupted in mid-cycle for short periods, long delays may result in poor performance such as wrinkled clothes from wash and wear cycles and incomplete washing where washer water was allowed to cool.

Such problem areas are partly simplified by logic devices which are sensitive, not only to appliance use, but also to the magnitude of current involved. This refinement will permit the use of a small range top element or appliance convenience receptacle without interrupting the use of the lower priority

WATER HEATER MAY OPERATE WHENEVER RANGE AND FREEZER ARE OFF
 FREEZER MAY OPERATE WHENEVER RANGE IS OFF BUT WILL PREVENT WATER HEATER OPERATION
 RANGE MAY OPERATE ANYTIME BUT WILL PREVENT FREEZER AND WATER HEATER OPERATION
 TOTAL MAXIMUM DEMAND LIMITED TO THAT OF LARGEST APPLIANCE

EXHIBIT C-1
 FUNCTIONAL DIAGRAM OF AUCTIONEERING LIMITER
 TYPICAL FOR THREE APPLIANCE CONTROL

load but will operate as described if the main heaters are selected. While one out of two logic devices are relatively easy to apply, generally one out of three systems must be given considerable thought if operation acceptable to the householder is to be obtained.

3.3 Application to a Utility System

The primary action of an actioneering device is to limit the kW demand of a particular customer without reference to system conditions or the consumption of other customers. While this may limit the total demand of the controlled location, the implication on a system basis is less clear. In fact, two different situations need to be recognized; the system effects at peak load and the more localized effect on the distribution network during the off peak times.

At the time of the system peak, the auctioneering load limiter will be of benefit in limiting the customer's individual demand in those cases where the customer's life style requires the use of electrical apparatus coincident with the system peak. However, due to the nature of the device in establishing priorities, the very action of disconnecting one device in favor of another must result in a deterioration of the natural diversity. Thus, the penalty for a reduction of demand per customer is likely to be a prolonged undiversified load of the controlled device upon reconnection. This characteristic, taken over one customer class within a distribution area could result in the destruction of the inherent diversity assumed in the original network design. Add to this the random nature of the time relationship between the individual customer usage and the system peak and it is not inconceivable that the system peak will be broadened and possibly any kW savings eliminated by the loss of customer class diversity.

During off-peak periods, the device continues to operate as previously described with similar characteristics. While the system effects are negligible, households with similar life-styles fed from a common low voltage transformer may impose unexpected loads upon that transformer due to a worsening of the diversity and the consequent increase in the total demand over that for which the transformer was sized.

3.4 Compatibility With Load Control Objectives

The use of auctioneering devices is to limit the kW demand of individual customers. Nevertheless, the use for system peak load control is not recommended as the function is unpredictable due to there being no direct correlation between the time of the kW saving and the system peak.

Should a load control program include the use of a rate structure with demand charges, then such customers exposed to this charge could benefit from the auctioneering function and there would be

much merit in its application due to its simplicity and effective operation. Should such demand charges be applicable over limited periods, a time control of the auctioneering circuit could be added to prevent continuous and needless operation.

4.0 Preprogrammed (Fixed) demand Limiter

4.1 Operation

This device is an application of solid state circuitry to what is essentially time of day control - an application which brings to the time switch type of control the benefits of multiple logic functions.

In the simplest form, the device is a solid state time switch with the ability to differentiate between week days and weekends, identify fixed holidays and provide for the non-uniformity of the calendar. In addition to this facility, a "read only memory" chip may be programmed by the manufacturer in accordance with any particular utility's load profile and the combination of these two functions plus an outside air temperature input enable the device to anticipate system peak load periods. Such periods, when identified as likely to occur, are preceded by a program which may preheat (or precool - if an air conditioning load is to be controlled) above the customer set temperature and at the time for control of demand, initiates a controlled ramp down of the internal temperature to a preset low temperature. The controlled load may be cycled to obtain the required ramp slope and the minimum low value. At the end of the controlled period, the temperature is restored to its normal value. One possible profile for such an application is given in Exhibit C-2.

4.2 Use

The device is in essence a "smart" two temperature, timed set back thermostat and is installed and operated by the customer as such. Only the preprogrammed portion is beyond his/her control. On loss of power, the device timing function ceases and must be reset by the customer after the outage - the need for this action may be annunciated. The incentive for the customer to pay attention to the unit is that it replaces the normal thermostat and becomes the only point of control for the heating/cooling cycle.

4.3 Application to a Utility System

Provision of the required load profile information to the manufacturer for input into the load limiter memory is the major involvement of the utility in the application of these devices. The effect on the network of the use of such load limiters will be mainly beneficial, due in part to a built-in random time interval which controls the load restoration following a control period and prevents the sudden

EXHIBIT C-2
CHARACTERISTIC OF PREPROGRAMMED DEMAND LIMITER,
TYPICAL APPLICATION FOR HEATING

application of a non-diversified load. It should perhaps be mentioned that the "preheat" or "precool" period just prior to a projected peak load situation may result in the destruction of the diversity and problems due to overloading may occur in isolated locations within the system.

More important, the net result of the use of limiters with pre-control logic to boost temperatures prior to the control period must be to lengthen the period of the peak and there is always the risk that a pre-peak secondary peak may be created. This would invalidate the pre-programmed load profile and such a change in the device memory would be a major expense.

4.4 Compatibility With Load Control Objectives

The use of pre-programmed demand limiters do effectively control kW demand and due to their internal logic, can be expected to function only on days which will be peak demand days or which have the characteristics which may lead to a peak demand day. Unnecessary control of the customers' load is avoided, a factor which could lead to greater customer acceptance.

An additional benefit may be gained if the limiter is coupled with a utility operated communication channel and the outside temperature sensor replaced by a suitable receiver. The utility may then transmit an "enable" signal to the limiters on days when peak conditions are expected to occur and so obtain control on peak days only. A second potential benefit exists with this latter modification in that should a peak condition occur due to the network problems, demand limiting may be obtained regardless of the temperature.

It should be noted that the device logic will allow such an external override only if the external signal occurs within system peak time profile stored in the memory. The external signal cannot shed load on demand and is limited to initiating the pre-programmed ramp setback.

5.0 Programmable Load Limiters and Energy Management Systems

5.1 Operation

This category of equipment is the most versatile form of self-contained local logic equipment and is generally capable of both kW demand control and kWh utilization control. Based upon micro-computer technology, read/write memory functions permit complex logic programs to be written and executed and, if necessary, modified according to day-to-day operations. The ability to calculate demand, either from a contact generated pulse from a kWh meter and a demand period signal or alternatively from current and voltage measurements permits precise limits to be adhered to

with respect to "do not exceed" and "restore" values. A number of methods are available, depending in part on the equipment manufacturer, for the determination of the electrical demand and the initiation of kW demand control, but in general, all fall into one of three broad categories:

A. Linear or Ideal Rate

An ideal rate of kWh consumption to achieve a given kW demand over a given time period is that which is constant throughout the time period; i.e., the relationship between kWh and time is linear. If the actual kWh consumption exceeds this theoretical consumption at any time during the demand period, this is interpreted as exceeding the preset limit and load reduction is initiated. Load is restored when the actual consumption falls below the ideal rate.

Exhibit C-3 shows this principle diagrammatically. Two particular points are worth noting. The ideal line is offset from the origin vertically to ensure that at the start of the demand period, the theoretical kWh is always greater than the actual. This is required to prevent unnecessary load reduction at the start of each timed interval. Margins are provided between the theoretical line, the control "off" setting and the "restore" setting to ensure that any possible overshoot will fall below the maximum set point and to prevent hunting which would result in on and off sequences in rapid succession.

B. Prediction

At definite times during the demand period, the actual kWh consumption recorded from the start of the period (real component) is added to the product of the instantaneous rate of consumption and the time remaining in the period (predictive component). Should this total value exceed the preset limit, load control is initiated; if this value is below the limit, any previously interrupted load is restored. Exhibit C-4 demonstrates this principle.

C. Instantaneous Rate

This is similar to the ideal rate category in that an ideal rate is assumed for a given maximum demand but in place of the comparison of accumulated kWh consumptions, this uses only the slope of the ideal and actual curves as indicated in Exhibit C-5. Should the rate of kWh consumption over a small time interval exceed the ideal rate, load control is initiated to reduce the rate of consumption. Conversely, a rate less than the ideal rate will permit restoration of any previously interrupted load.

EXHIBIT C-4
CHARACTERISTIC OF DEMAND LIMIT
USING PREDICTION METHOD

EXHIBIT C-5
CHARACTERISTICS OF DEMAND LIMIT
USING INSTANTANEOUS RATE METHOD

Perhaps the most significant characteristic of this principle is that while the slope of the ideal curve is determined from the demand period in use, the actual measurement and the final control action is independent of the demand period and a true kW peak limit is obtained throughout the control action.

In addition to the kW demand control functions, these devices may be provided with kWh utilization functions in the form of programmed control of time related functions such as security lighting, plant heating, cooling and prestart of plant processes following weekends, etc. This control may be integral with or independent of the demand control function.

Interface with the controlled load is an integral portion of the control strategy and varies quite widely between equipment. Typical facilities offered may include circuit priority, first off-first on, first off-last on, minimum time off, maximum time off per hour, maximum operations per time period, etc.

5.2 Use

The principal application of these devices will be found in larger commercial and industrial installations and they are used for the primary purpose of a reduction of the cost of electrical power. While the most significant savings can be expected in the control of the customer's peak demand, energy management on a facility-wide basis in controlling the unnecessary use of installed facilities can result in significant savings in kWh consumption. Apart from the incentive introduced by peak demand rate schedules, little coordination is to be expected between the requirements of the customer and the utility. In fact, the supply of utility services to a plant is generally a relatively small proportion of the total product and disruption of production to accommodate "third party" requirements is unlikely. Nevertheless, with increasing power costs, the use of these controllers will increase.

Application of a programmable load limiter to an installation requires a detailed load survey in order to determine all loads which may be controlled, with respect to both magnitude of the load and its priority. These survey results, together with the examination of past billing and determination of plant load factor, will indicate whether kW demand or kWh savings are required for maximum benefit. A secondary but important benefit of such a survey is to eliminate a common defect where, after the expenditure of considerable funds, the load control actually achieved is somewhat less than predicted due to equipment selected for control which was not normally operating during the periods of control.

The choice of hardware must be made early in the program in order to determine auxiliary equipment requirements. Selection of the controller is important to the success of the system, but the

communication system by which the controller will issue commands to the individual loads may influence the cost in the order of several times the price of the controller depending upon specific problems. This must be recognized. Such a communication channel may be typically direct wire full voltage control, direct wire reduced voltage control using interposing relays, carrier current coded injection over the plant distribution system (commonly referred to as wireless control), radio control (usually UHF) or data channel multiplex. The direct wire control is the minimum cost system but is vulnerable to plant interference, may present awkward routing problems and be time consuming to install. Wireless and radio systems require the minimum modification to plant wiring and have the maximum flexibility for change. Data channel multiplex is ideally suitable for plants containing many individually controlled loads situated in groups remote from the controller.

Another consideration included during the feasibility and estimating stage must be the facility present in each circuit for remote control. While heating and cooling loads generally have thermostat control and permit remote controls to operate via the thermostat wiring, many loads frequently selected, such as lighting, small motors, etc. do not have similar equipment. All such load circuits must be provided with remote control contactors or motor starters as part of the load control program. This will usually result in the need to purchase suitably rated equipment and housings together with the associated extensive wiring changes. Also, the safety aspect cannot be ignored and measures must be taken to protect personnel from the potentially harmful effects of starting machinery from a remote source, machinery which may not have been designed for such use.

Determination of the final control program and the method of implementation will vary widely between different types of equipment and may be expected to range between extremes of presetting switches to complex software programs. The latter, applicable more to the total energy management system installations than to demand controllers, are usually available at a nominal charge from the supplier or will be provided as a service by the manufacturer.

5.3 Application to a Utility System

As stated previously, the main purpose of this equipment is to reduce the total cost of purchased power for the installation concerned and while the limiting of individual customers kW demand may have a beneficial effect on the utility's system when such demand limiting is coincident with the system peak, such action is unplanned and random. Thus, no credit can be taken for this type of load limiting device in the day-to-day operation of the utility. A more important consideration is that of the secondary effects of demand limiters where such devices utilize the demand metering interval pulse for the determination of demand - notably those using the ideal rate or prediction basis for load control. Both these systems will tend to initiate load shedding towards the end

of a demand period and will restore all load at the commencement of the next demand period. Should the utility use the same time intervals for demand timing, this load restoration will occur at or about the same time and result in potentially large load surges on the system. Widespread adoption of this principle must be examined, in detail, to ensure that the network can tolerate this transient loading.

5.4 Compatibility With Load Control Objectives

Control of load by programmable load limiters does not meet the requirements of load control objectives as viewed from a total system standpoint. These devices do effectively limit kW demand at the installed location, but they are insensitive to coincident system peaks on peak days, such considerations being unconnected with the primary purpose of limiting billable demand.

In most applications, the utility has no means of remotely operating these devices to achieve a form of load control and this is to be expected, as it is considered unlikely that any large establishment would be willing for an external agency to control portions of its operation directly. However, it is not impossible that favorable consideration would be given for the utility to initiate the load reduction program by means of a remote signal and by this means, some form of load control benefit may be obtainable. With the use of systems using selectable programs, separate programs suitable for continued plant operation could be written covering demand reduction over system peaks and emergency periods, independent of the billing demand reduction program and these can be made available for implementation upon receipt of an appropriate signal from the utility. As this latter facility would be more applicable to very large installations, the control benefits would also be significant.