Simulation of Costs and Benefits for Electric Utility Direct Load Control

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ABSTRACT

PURPA required all state utility regulatory commissions to consider a number of rate-making standards, including direct load control techniques. Relevant questions to both utilities and regulators are whether direct load control is practicable, reliable, and cost effective and whether it will provide useful energy or capacity management advantages. This paper describes the results of a project which developed a methodology and simulation model to help answer these basic questions. The software program developed uses Monte Carlo production costing and reliability analysis routines, and simpler consumer response and utility financial models. Generic utility data were used to test the methodology and the simulation model; depending on the assumptions used direct load control can be an economical utility load modification technique. The study also points out some pitfalls in typical analyses performed in the past.

INTRODUCTION

The major objectives of utility load management programs are to defer capital investment in new power plants and to promote the efficient use of energy resources. Load management strategies fall into two broad categories: active (when the utility controls the customer's loads) and passive (when the customer voluntarily controls his own loads). Active load management, commonly called direct load control (DLC) offers significant potential for improving electricity load factors. This point was recognized in the Public Utilities Regulatory Policies Act (PURPA) of 1978 which required state regulators to determine whether a number of rate standards should be implemented [1], including direct load control.

To facilitate the analysis of rate design issues, the Florida Public Service Commission funded a project on "Metering for Innovative Rates" which was conducted by the Public Utility Research Center at the University of Florida and was reported in [2] and [3]. One of the goals of this project was to develop a cost-benefit methodology and computer simulation model to evaluate the cost effectiveness of direct load control. This paper discusses the practice of direct load control, reports the results of the computer modeling and simulation of DLC, and describes the customer response to DLC programs. The results of this project show that based on the generic utility data used DLC is an acceptable and cost effective technique for utility load modification.

DIRECT LOAD CONTROL

A variety of direct load control devices are available which either allow utilities to directly cycle off particular appliances (like hot water heater or air conditioning units), or to place limitations on the usage of electricity [4]. Examples of the latter would be clock operated switches (without remote control), interlocks (preventing simultaneous use of particular appliances) and temperature initiated switches that override thermostats. Alternatively, remote-control devices can be activated by radio waves, high-frequency impulses over a power line, low-frequency ripple signals over a power line, or telephone pulses. Many on-going load shaping tests are exploring the short run impacts of DLC on automatic meter reading and control, and the control of heating loads [5, 6]. One notable gain from active load control is improvement in system reliability, since the need for back-up capacity is reduced.

The utility load reduction possible through DLC is a direct function of the number of appliances in use and the percentage of these appliances that are connected to control switches. Present DLC equipment technology is such that separate control switches are required for each appliance. Thus, a given customer could easily have three control switches; or more if several water heaters or heating/air conditioning units were in use. Although DLC of space heaters and air conditioners would not occur simultaneously, customers could have the water heater and the air conditioner, or the water heater and the space heater controlled at the same time.

The potential number of installed DLC switches is quite large, presenting several difficulties in the implementation of large scale DLC programs. First, the customers with appropriate appliances must be identified in some manner. Next, these customers must be contacted to determine how many of them would be interested in a voluntary DLC program. For a mandatory DLC program this step would not be needed. Once the total number of DLC installations desired is determined, the utility must decide on its own rate of implementation. It is unlikely that any large utility would try to implement a total DLC program in a short time, e.g., one year. More likely is a phased-in program covering around five years, and possibly ten. For a phased-in program, selection of customers for installation of DLC switches could be a critical factor to the optimum benefit of the program. Since DLC of 50% of the residential customers might easily produce 75% or more of the overall program benefits, it appears natural to try to control these more cost-effective customers first. (A cogent discussion of these issues is given in [7].

THE SIMULATION MODEL

The EMIR (acronym for Engineering/Economic Model for Innovative Rates) software program developed through the project is simple in some respects and sophisticated in others. While it omits some of the detail of the corporate models used by larger utilities, it contains some regulatory policy, demand elasticity, and rate structure variables which make it a more powerful analytic tool than has previously been available. The model both simulates the hourly operation of a utility and allows for expansion of capacity over a ten-year horizon, based on reliability requirements. A major effort has been made to capture the interaction among metering technology, customer response (based on underlying consumer preferences) and cost-effective rates. The resulting analytic framework and the incorporation of that framework into a software package represents a significant contribution to policy-making in this exceedingly complex area.

The cost/benefit methodology has been incorporated into the EMIR package to permit sensitivity analyses of key vairables, such as metering costs, changes in usage patterms, and associated operating costs, and modifications in the expansion plan. The program enables the user to compute reliability indices, calculate revenues and costs, and determine various financial ratios. Flexibility has been emphasized to facilitate changes in the programs, which now allows the user to assess the effects of DLC and other innovative rate structures. Each metering technology/innovative rate structure yields a reliability profile, i.e., loss-of-load probability for each month over the planning horizon. Furthermore, a financial accounting model takes a Balance Sheet and supporting data loaded at the beginning of the run, and creates annual Income Statements and new Balance Sheets. The financial statements are functions of many variables which themselves depend on the utility system, regulatory environment, and financial situation.

The major components of EMIR consist of models for hourly load; generating capacity; revenues; costs of fuel, O & M and depreciation; expenses like interest, taxes, and dividends; system reliability; and financial variables which affect the capacity expansion plan and the final benefit-cost comparison. The load modification subroutines take into account meter penetration, percentage of hourly load metered, and elasticities (reflecting customer consumption responses to innovative rates). Regulatory policy determines both the allowed rate of return on rate base and the price structure; to hold the utility to its allowed return a customer "rebate" is calculated. Without such an artifact complicated regulatory feedbacks would have to be introduced into the model; however, if prices are changed, then the entire hourly-load/production-costing loop would have to be re-entered. Thus, the simplified model of ex post rate regulation allows financial comparisons to be made with the base case.

GENERIC UTILITY TEST

In order to test the cost/benefit methodology developed in this project, data from a hypothetical Florida utility were constructed using information from several Florida utilities. This utility test involves a generic Florida utility (GFU) which is not intended to represent any specific Florida company, but does reflect the general characteristics of most utilities in the state. Since the purpose of this project was to develop a tool for the Florida Public Service Commission to use for policy making the decision was made by the project team to avoid using data from an identifiable utility. This prevented the potential problem of the research team becoming involved in a specific regulatory hearing.

The generic utility test was performed to analyze the costs and benefits of a DLC structure. The benefit/cost analysis of DLC for a sample utility requires production statistics and capacity additions with and without DLC. The production and capacity statistics and associated costs are determined for a typical utility using the Monte Carlo computer simulation package developed for this project. As such, the results describe the production and capacity expansion statistics and cost over a ten-year planning window. By comparing these results for both the base-case and DLC case, the required data to complete the benefit/cost analysis is obtained.

The input requirements for this utility test are similar to those for any probabilistic analysis. In broad categories, the inputs required are:

1. Load Model
2. Unit Performance Models and Data
3. Fuel Data
4. Reporting Requirements
5. Financial Data
6. Elasticities and Peak/Off Prices

The load model is developed from EEI (Edison Electric Institute) formatted hourly demand data. By determining the averages and standard deviations for each hour of the three typical days (weekdays, Saturdays, and Sundays) in each week, the projected annual peak demand is translated into an annual simulated hourly demand profile - which represents the load model. This model of the load is used to determine all of the production statistics associated with the operating utility being simulated. When DLC is being considered, the annual hourly loads are modified to reflect the consumer's response to the DLC signals.

The EMIR simulation package activates the DLC on the basis of particular generating units. The diversified KW demand under control in a given season determines which units serve as "trigger units," so that if demand and the availability of other units would cause such units to be started, DLC is instituted instead. Of course, the estimate of diversified demand of air-conditioning systems is dependent on assumptions about temperature; on mild days, there is less controllable load, although there is also less likelihood that DLC will occur on such days. Another EMIR feature is energy recovery, which is user specified: recovery will depend on customer behavior and appliance/housing characteristics. In the case of hot water heaters, DLC will tend to reduce tank temperatures so heat loss is less; in addition, customers will use water at a lower temperature. Besides being sensitive to weather and temperature patterns, both energy and demand patterns depend on duration of control, the magnitude of the system peak, and the schedule of control.

The hourly modeling of cost savings represents an improvement over software packages which alter the annual load shape in some simplistic way, without addressing the operating implications of DLC. The control patterns as experienced by individual customers are not modeled in EMIR although average incidence and duration can be calculated from print-outs.

DLC SIMULATION RESULTS

In order to evaluate the appropriate costs and benefits of DLC, it is necessary to determine the extent of customer interruption during a typical year. Customer dissatisfaction is generally going to be directly related to the number of times the DLC switch shuts off a given service, as well as the length of time that service is unavailable. The computer simulation keeps track of the total amount of time during each month that the DLC system was activated, as well as the total amount of KWH that were shed during this time. However, the simulation does not disaggregate the results into which customers and which loads were actually affected, nor into the actual number of times a given customer is subjected to DLC action. Thus, the simulation results must have some external properties associated with them in order to determine the impact on specific groups of customers, or the average customer.

Since DLC of water heaters is least disruptive of customer service, an assumption is made that water heaters are always the first appliance to be controlled. If sufficient load can be shed using only water heaters then no control action for room air conditioners or space heaters (depending on the season) will be employed. Only when load shedding above that provided by water heaters is required will another appliance be subjected to control. The control action for water heaters is to simply turn them off for periods of up to four hours, with no cycling off and on. Control actions for air conditioners or space heaters will involve cycing, with periods of at least 15 minutes out of an hour required to produce load reductions. Thus, some degree of impact on groups of customers can now be determined using these externally imposed rules of how the DLC load shedding decisions would actually be implemented.

Several EMIR DLC simulation scenarios were run for periods of ten years starting with 1978 as the base year. The data used in these runs assumed that when a DLC sig-

nal was sent out by the utility that there was a 1.0 KW reduction in demand for each controlled electric resistance water heater, central electric air conditioner and electric resistance space heater. Florida's peak load periods are in the winter when heavy use of electric space heaters is prevalent, and the summer when use of air conditioning is dominant. Florida is a winter peaking state primarily due to the needle peaking problem created by South Florida residents who only turn on their electric heaters on the coldest day or days of the year. The air conditioning peaks are lower, but are much broader due to the lengthy hot, humid Florida summers.

Simulation data for the two typical months of February and July are selected for discussion. One winter season month is to evaluate water heater and space heater control, and one summer month is selected to evaluate water heater and air conditioner control. The specific months are February and July, 1981, from the ten year 1978 simulation run. Using the 1981 customer population and the number of controlled devices we have the following load shedding ability (from Tables 1 and 2):

Winter

Space heating control		410.6 MW
Water Heater control		959.6 MW
	Total	1370.2 MW

Summer

Air conditioner control		645.2 MW
Water heater control		959.6 MW
	Total	1604.8 MW

Partial simulation output for the month of February is shown in Table 1. Evaluation of the load shedding data for February, 1981, shows that a total of 101 hours of load shedding occurred. Maximum load shedding was required less than 20% of the time of control, with a period of 16 hours where all of the space heaters and all of the water heaters were controlled. The simulation data is not disaggregated to the extent that total time periods of control can be determined. Thus, at present we cannot tell whether there were 16 days with one hour of control each day, or some combination such as 5 days of control for 3 hours a day and one day for one hour. A summary of the control action for February is given below:

Space heater control

16 hours for 100% of customers

Water heater control

101 hours total time of control

17 hours for 100% of customers

21 additional hours for 50% or more of customers

56 additional hours for 10% or less of customers

The conclusion for this data is that over 80% of the need for load shedding during the month of February was accomplished by water heater control, with essentially no customer inconvenience. The maximum inconvenience would be associated with the space heater control, and that would affect all customers with electric space heaters sixteen days for one hour a day, at the worst. Of the 101 total hours of load control, 56 hours affected only 10% or less of the customers with electric water heaters. Thus, the customer inconvenience or dissatisfaction would seem to be quite small for this sample winter month.

Evaluation of the load shedding data for July, 1981, shows that a total of 157 hours of load shedding occurred. Maximum load shedding was required less than 3% of the time of control, with a period of only 4 hours where all of the air conditioners and all of the water heaters were controlled. A summary of the control action for July is given below:

Air conditioner control

4 hours for 100% of customers

Water heater control

157 Hours total time of control

20 hours for 100% of customers

38 hours for 50% or more customers

53 hours for 10% or less of customers

The conclusion for this data is that over 97% of the need for load shedding during the month of July was accomplished by water heater control, with essentially no inconvenience for customers. Only 4 of the 157 hours of control required air conditioners to be cycled. Just 38 hours of control affected 50% or more of the water heater customers, and 53 hours affected 10% or fewer customers. Thus, the customer inconvenience or dissatisfaction is even reduced for this summer month, although more total hours of control were involved. The explanation for this result is that Florida is a winter peaking state, and the need for the greatest peak load reduction occurs in the winter, although for short periods of time. Alternatively, summer peaks are lower and longer, requiring a smaller magnitude of control for a longer period of time. Therefore, the water heater control provides almost the total effect needed for a typical summer month.

DLC ENERGY RECOVERY

The extent of energy recovery is one key variable affecting the benefit and costs of this DLC innovative rate. The object of a DLC program is to shift some of the contribution to a utility peak time into a shoulder or off-peak time. For example, a water heater might be shut off through DLC for a four hour period during a utility system's peak. In order to compensate for this reduced use during the on peak time, the water heater would have to operate more frequently during the off peak time. The load deferred by DLC will usually be paid back or recovered during shoulder or off-peak times. In some cases, the "payback" or "recovery" may be less than 100%, as in the case where a service is simply foregone, rather than deferred. For example, a controlled air conditioner might be completely turned off by a customer after the hottest part of the day. Thus, the air conditioner unit would not be allowed to run in order to produce the "deferred cooling." For water heating, the recovery could be less than 100% if some use of hot water were just avoided in order not to deplete the DLC controlled tank contents. This might occur by deciding to wash a load of clothes in cold water, rather than hot water, for example.

In most cases, recovery of 100% is assumed so that customers only defer the service concerned rather than eliminating that service altogether. With 100% recovery, the only reduction in customer benefits is the dissatisfaction involved in deferring the service to a later time. Personal life styles are significant here in terms of the loss involved. If clothes washing and taking showers can easily be done in off-peak times then little, or no, loss of benefits occur due to DLC of a customer's water heater. Similarly, if DLC of air conditioners or space heaters produces no detectable change in comfort levels then there is no loss of benefits.

CONSUMER RESPONSES

If some level of inconvenience or discomfort from DLC programs occurs, then there must be an evaluation made as to the value of the service loss when compared to the incentive to participate in the program. The value of a customer's dissatisfaction or discomfort is hard to assess in most cases. However, the bottom line is whether a given customer feels that the reduction in cost of electricity due to participation in a DLC program is more significant than the dissatisfaction or discomfort experienced.

In certain cases, customer behavior patterns can have a negative impact on the expected results of a DLC program. For example a customer subjected to DLC of a hot water heater might respond by turning the temperature up on the tank in order to have a greater supply of hot water. This customer action results in an increased load from water heating, and if practiced by enough customers could cause an increase in the amount of time DLC would have to be exercised for all water heating. Customers altering thermostat settings in air conditioners and space heaters could also result in more extensive control time. If a customer whose air conditioner is presently being cycled off 15 minutes out of each hour turns his thermostat down several degrees in response, then the DLC demand reduction is lessened, and the time of DLC control action must be lengthened. A similar result occurs when the thermostat setting on a space heater is increased due to DLC.

In addition to these short term actions which partially defeat a DLC strategy, there are other customer actions which could have even more negative impact on the DLC program. A customer with central air conditioning under DLC might purchase a window unit which would not be on DLC in order to "retain full control of their comfort," [8, 9]. Similarly, a portable electric space heater would partially defeat the benefit of DLC of central electric space heaters. Even water heater DLC could be affected by customers who purchased small electric water heaters to supplement the large controlled unit. Other long term customer actions could involve replacement of existing applicances which fail with new, oversize units. Replacing an air conditioner compressor unit rated at 36,000 BTU with one rated at 48,000 BTU could result in the new unit running substantially less often to provide the same amount of cooling as before. The net effect of this larger unit would be that it produced less demand reduction under DLC than the smaller unit. Similar possibilities exist for oversize space heaters and water heaters.

While all of these aspects of customer behavior could potentially reduce the effectiveness of DLC programs, the crucial question is how often will customers engage in such actions? This question is very difficult to answer since little controlled research has been performed regarding the issue. There is no doubt that such DLC defeating customer actions can actually take place; the magnitude of the number of customers involved is what is not well known. Customer actions which defeat the DLC program will only occur if the customer actually experiences discomfort from the control action. In the survey of large load management programs reported by Capehart [10], very little customer dissatisfaction was communicated to the utilities involved. Virtually no complaints from loss of hot water were reported by any of the utilities having large numbers of hot water heaters under control for as long as four hours. Most customers never knew that their water heaters were shut off. In the case of controlled air conditioners, more customers recognized that their units were shut off, but few reported any inconvenience to the utility. Thus, it seems reasonable to conclude that there may not be any major negative impact due to customer actions to defeat DLC programs.

Negative impacts in DLC programs that are not well designed may be an entirely different matter. If control action is very frequent and/or of long duration then customer dissatisfaction will quickly surface. Once customers recognize that there will be extensive periods of discomfort from control of any appliance then they may very well start taking action to defeat the DLC program. The success of a given DLC program would seem to be very dependent on the amount of control action required in order to produce a positive benefit. If the expectations of a DLC program are not unreasonable, it would seem likely that little customer action to defeat the program would actually occur.

Another aspect of long term impact of customer behavior on the results of DLC programs is that involved with movement over time to a more energy efficient existence. Here the customer has no specific intent to reduce the effectiveness of a DLC program but only to save energy by purchasing and installing higher efficiency appliances and devices. As higher efficiency central air conditioners become available, for example, customers will purchase these units in many cases and thereby offset the amount of load reduction possible by DLC of that new unit as contrasted to the old unit. Addition of insulation, caulking and weatherstripping and other such improvements will also result in reduced use of existing heating and air conditioning units, also reducing the effectiveness of DLC. Thus, the normal customer behavior over a period of years to improve the energy efficiency of their homes will ultimately reduce the potential benefit from load management. Improved energy efficiency standards for new construction will also result in lower benefits of DLC programs when compared to programs in similar sized housing that does not meet new building code requirements. However, these reduced DLC loads occurring as a result of making residences more efficient will also reduce the demand and energy loads on the utility providing the service. The net result should be an overall improvement for the utility, since now the DLC system is not their only mechanism for improving system load factor.

CONCLUSION

In the particular scenario analyzed here, there are fuel savings from DLC. The key determinants of net benefits are potential customer responses (just noted) and capacity savings. Currently, many utilities are not at optimum scale or generation mix; capacity deferrals or cancellations depend on utility-specific situations. However, there is no doubt that the savings from direct load control programs will grow over the next decade. Whether such programs substitute for (or complement) other rate design programs (such as time-of-use pricing) is still an open issue. However, microprocessor technologies will continue to make a multifunction metering program look more cost-effective.

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TABLE 1

FLORIDA GENERIC UTILITY (DATA/B78)
UNIVERSITY OF FLORIDA DEPARTMENT OF ELECTRICAL ENGINEERING
PRODUCTION SIMULATION METHOD COMPATABLE WITH LOAD MANAGEMENT
** 1978 DLC CASE **

DIRECT LOAD CONTROL SUMMARY FOR FEB

HOUR	WEEKDAYS SHED MWHE	WEEKDAYS SHED NUM	WEEKDAYS RECOVERY MWHE	WEEKDAYS RECOVERY NUM	WEEKDAYS PEAK MWE
1	106.6	2.0	2284.8	3.0	56.4
2	0.0	0.0	3044.9	4.0	0.0
3	0.0	0.0	3094.0	2.0	0.0
4	0.0	0.0	2866.8	2.0	0.0
5	0.0	0.0	1105.3	1.0	0.0
6	18.0	1.0	577.8	1.0	18.0
7	766.1	3.0	18.0	1.0	694.6
8	4386.1	11.0	17.5	1.0	1370.2
9	4588.4	10.0	165.7	5.0	1370.2
10	4201.7	6.0	180.9	7.0	1370.2
11	2699.8	7.0	190.0	4.0	1370.2
12	1391.4	6.0	107.9	4.0	828.9
13	354.8	3.0	196.5	5.0	327.2
14	30.4	1.0	490.7	4.0	30.4
15	0.0	0.0	1581.9	5.0	0.0
16	0.0	0.0	1646.5	4.0	0.0
17	72.3	2.0	252.8	3.0	45.9
18	1173.3	7.0	26.4	1.0	676.7
19	3035.4	6.0	58.4	2.0	1370.2
20	3971.6	9.0	5.5	1.0	1370.2
21	3049.6	5.0	287.9	6.0	1370.2
22	1943.9	7.0	111.6	3.0	1179.8
23	739.4	1.0	362.9	7.0	739.4
24	76.8	3.0	199.3	2.0	37.8
MONTHLY TOTAL	33085.7	90.0	18874.0	78.0	1370.2

	SATURDAYS SHED MWHE	SATURDAYS SHED NUM	SATURDAYS RECOVERY MWHE	SATURDAYS RECOVERY NUM	SATURDAYS PEAK MWE
	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0
	25.8	2.0	0.0	0.0	14.2
	0.0	0.0	25.8	2.0	0.0
	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0
	6.4	1.0	0.0	0.0	6.4
	0.0	0.0	6.4	1.0	0.0
	46.9	1.0	0.0	0.0	46.9
	0.0	0.0	46.9	1.0	0.0
	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0
	60.1	1.0	0.0	0.0	60.1
	139.2	5.0	79.1	4.0	60.1

	SUNDAYS SHED MWHE	SUNDAYS SHED NUM	SUNDAYS RECOVERY MWHE	SUNDAYS RECOVERY NUM	SUNDAYS PEAK MWE
	32.5	1.0	0.0	0.0	32.5
	0.0	0.0	32.5	1.0	0.0
	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0
	55.4	1.0	0.0	0.0	55.4
	0.0	0.0	55.4	1.0	0.0
	36.2	1.0	0.0	0.0	36.2
	0.0	0.0	36.2	1.0	0.0
	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0
	46.0	1.0	0.0	0.0	46.0
	0.0	0.0	46.0	1.0	0.0
	47.7	2.0	0.0	0.0	27.4
	0.0	0.0	47.7	2.0	0.0
	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0
	217.8	6.0	217.8	6.0	55.4

NUMBER OF HOURS SHEDDING OCCURED= 101.0
NUMBER OF HOURS RECOVERY OCCURED= 88.0

MONTH'S PEAK SHED (MWE)= 1370.2

WEEKDAYS= 50.0
SATURDAYS= 5.0
SUNDAYS= 6.0
TOTAL= 61.0

TOTALS FOR ALL DAYS OF THE MONTH

ENERGY SHED (MWHE)= 33442.7
ENERGY RECOVERED (MWHE)= 19170.9

RECOVERY TO SHED RATIO= 0.5732

TABLE 2

FLORIDA GENERIC UTILITY (DATA/B78)
UNIVERSITY OF FLORIDA DEPARTMENT OF ELECTRICAL ENGINEERING
PRODUCTION SIMULATION METHOD COMPATABLE WITH LOAD MANAGEMENT
** 1978 DLC CASE **

DIRECT LOAD CONTROL SUMMARY FOR JUL

HOUR	WEEKDAYS SHED MWHE	WEEKDAYS SHED NUM	WEEKDAYS RECOVERY MWHE	WEEKDAYS RECOVERY NUM	WEEKDAYS PEAK MWE
1	118.2	3.0	1471.2	4.0	57.6
2	0.0	0.0	1478.3	6.0	0.0
3	18.1	1.0	1788.8	2.0	18.1
4	53.4	1.0	2099.9	3.0	53.4
5	0.0	0.0	1733.7	3.0	0.0
6	11.3	1.0	1138.1	1.0	11.3
7	55.2	2.0	915.6	2.0	35.9
8	167.4	5.0	351.6	2.0	54.2
9	151.4	4.0	71.3	2.0	61.4
10	283.3	1.0	212.0	4.0	283.3
11	813.7	5.0	50.4	2.0	676.0
12	1476.0	5.0	79.3	4.0	982.3
13	2014.6	6.0	138.3	3.0	1209.2
14	2479.9	5.0	119.9	3.0	1374.8
15	2834.0	6.0	63.4	2.0	1476.0
16	3261.5	8.0	49.2	2.0	1551.1
17	4002.7	11.0	17.8	1.0	1604.9
18	4206.6	10.0	21.6	2.0	1604.9
19	3954.6	6.0	255.7	7.0	1462.9
20	2121.1	10.0	211.0	4.0	1167.3
21	1404.9	3.0	623.1	11.0	968.1
22	1156.1	4.0	340.9	4.0	707.5
23	383.4	6.0	213.5	4.0	186.0
24	82.5	3.0	239.3	5.0	33.5
MONTHLY TOTAL	30450.0	106.0	13684.0	83.0	1604.9

	SATURDAYS SHED MWHE	SATURDAYS SHED NUM	SATURDAYS RECOVERY MWHE	SATURDAYS RECOVERY NUM	SATURDAYS PEAK MWE
	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0
	2.9	1.0	0.0	0.0	2.9
	2.2	1.0	2.9	1.0	2.2
	0.0	0.0	2.2	1.0	0.0
	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0
	51.7	1.0	0.0	0.0	51.7
	228.0	1.0	51.7	1.0	228.0
	964.5	2.0	0.0	0.0	605.3
	1277.1	2.0	0.0	0.0	745.7
	1447.9	2.0	0.0	0.0	828.7
	1679.4	3.0	0.0	0.0	911.6
	1842.4	2.0	42.8	1.0	1020.3
	2107.0	2.0	0.0	0.0	1157.1
	2391.7	2.0	0.0	0.0	1313.4
	2051.7	2.0	0.0	0.0	1149.1
	1377.7	3.0	0.0	0.0	766.5
	1019.0	2.0	56.3	1.0	715.4
	417.5	2.0	0.0	0.0	405.9
	0.0	0.0	81.7	2.0	0.0
	135.6	3.0	0.0	0.0	58.1
	17016.4	31.0	237.6	7.0	1313.4

	SUNDAYS SHED MWHE	SUNDAYS SHED NUM	SUNDAYS RECOVERY MWHE	SUNDAYS RECOVERY NUM	SUNDAYS PEAK MWE
	27.7	2.0	46.8	1.0	14.3
	0.0	0.0	27.7	2.0	0.0
	61.1	2.0	0.0	0.0	32.7
	0.0	0.0	61.1	2.0	0.0
	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0
	0.0	0.0	0.0	0.0	0.0
	375.8	2.0	0.0	0.0	330.9
	421.2	1.0	44.9	1.0	421.2
	617.4	1.0	0.0	0.0	617.4
	723.6	1.0	0.0	0.0	723.6
	831.0	1.0	0.0	0.0	831.0
	955.1	1.0	0.0	0.0	955.1
	984.4	1.0	0.0	0.0	984.4
	747.6	1.0	0.0	0.0	747.6
	558.0	2.0	0.0	0.0	531.8
	477.2	1.0	26.1	1.0	477.2
	400.1	1.0	0.0	0.0	400.1
	367.1	3.0	0.0	0.0	315.9
	0.0	0.0	225.4	3.0	0.0
	7547.2	20.0	432.0	10.0	984.4

NUMBER OF HOURS SHEDDING OCCURED= 137.0
NUMBER OF HOURS RECOVERY OCCURED= 100.0

MONTH'S PEAK SHED (MWE)= 1604.9

WEEKDAYS= 56.0
SATURDAYS= 10.0
SUNDAYS= 7.0
TOTAL= 73.0

TOTALS FOR ALL DAYS OF THE MONTH

ENERGY SHED (MWHE)= 53013.6
ENERGY RECOVERED (MWHE)= 14353.5

RECOVERY TO SHED RATIO= 0.2609