INTELLIGENT AND INTEGRATED LOAD MANAGEMENT SYSTEM

by

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(ABSTRACT)

The design, simulation and evaluation of an intelligent and integrated load management system is presented in this dissertation. The objective of this research was to apply modern computer and communication technology to influence customer use of electricity in ways that would produce desired changes in the utility's load shape. Peak clipping (reduction of peak load) using direct load control is the primary application of this research. The prototype computerized communication and control package developed during this work has demonstrated the feasibility of this concept.

The load management system consists of a network of computers, data and graphics terminals, controllers, modems and other communication hardware, and the necessary software. The network of interactive computers divide the responsibility of monitoring of meteorological data, electric load, and performing other functions. These functions include: data collection, processing and archiving, load forecasting, load modeling, information display and alarm processing. Each of these functions requires certain amount of intelligence depending on the sophistication and complication of that function. Also, a high level of reliability has been provided to each function to guarantee an uninterrupted operation of the system. A full scale simulation of this concept was carried out in the laboratory using five microcomputers and the necessary communication hardware.

An important and integral part of the research effort is the development of the short-term load forecast, load models and the decision support system using rule-based algorithms and expert systems. Each of these functions has shown the ability to produce more accurate results compared to classical techniques while at the same time requiring much less computing time and historical data. Development of these functions has made the use of

microcomputers for constructing an integrated load management system possible and practical. Also, these functions can be applied for other applications in the electric utility industry and maintain their importance and contribution. In addition to that, the use of rule-based algorithms and expert systems promises to yield significant benefits in using microcomputers in the load management area.

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Chapter I

INTRODUCTION

The goal of this dissertation is the design, simulation, and evaluation of a general purpose, intelligent, and integrated load management system. This system will use load management to modify the load patterns seen by the utility system. However, peak reduction using direct load control will be the primary avenue for achieving some objectives such as postponing of capacity additions and energy cost reductions.

1.1 Background

Since the early 1970's, economic, political, social, technological and resource supply factors have combined to change the utility industry's operating environment and outlook for a new future. The electric utility industry faces staggering capital requirements for new plants, significant growth in peak demand, and declining financial performance.

The number and diversity of alternative generation processes has made planning and operating a utility more difficult. Nuclear units, pumped storage, combustion turbines, and

other new types of generation have forced the industry to develop plans and operating strategies for generations with widely differing characteristics and costs.

In this context, it appears that much can be gained by the utility and consumer by trying to slow down the peak-load growth rate and improve the load factor thereby increasing the efficiency of the power system. A slowdown in capacity expansion would have a beneficial effect on the average cost of electricity, since new construction is significantly more expensive than the embedded cost of existing plants. Also, higher utilization of existing and new plants would allow overhead costs to spread over a larger volume of sales, thereby lowering costs on a cents per kilowatt-hour basis. In the long run, an increased load factor would allow a shift towards a greater proportion of baseland coal and nuclear generation.

While load management is not the cure for all of these problems and other problems facing the electric utility, it provides utility management with many significant alternatives. Also, it represents a fundamental change for much of the utility industry.

1.2 Load Management

Demand side is usually defined as the planning and implementation of utility activities designed to influence customer use of electricity in ways that will produce desired changes in the utility's load shape (i.e., changes in the time pattern and magnitude of a utility's load). Utility programs falling under the umbrella of demand-side management include: load management, new uses, strategic conservation, electrification, customer generation, and adjustments in market share.

Load management is the set of utility activities designed to influence the timing and magnitude of customer use of electricity. A number of methods exist for modifying system load patterns to more closely match electric energy use with supply.

Load management may be a means whereby an electric utility can (1) reduce the requirement for additional generation, transmission, and distribution investments; (2) improve

the efficiency of the electric utility; and (3) shift fuel dependency from limited to more abundant energy resources.

Figure 1 illustrates how load management can reduce the requirements for peaking capacity and increase the utilization of more efficient baseload capacity (i.e., nuclear and coal). The upper graph shows the typical annual load duration curve without load management (the solid line). In the same graph the dotted line represents the modified load duration curve after moving energy from the hour of high demand to the hour of low demand. The lower graph is a screening curve representation of the levelized annual cost of operating various types of generating units. As the number of hours of operation increases, the total cost increases because of fuel, operation, and maintenance costs. Efficient baseload units (units 3 and 4), generally have higher capital costs, but the cost curves have a flatter slope because of the increased efficiency. Units 1 and 2 represent less efficient intermediate and peaking generation with lower capital costs. The cost curves of these units size more rapidly as hours of operation increases.

Although load management techniques have been practiced in Europe more extensively than in the U.S., the European experience has demonstrated that the impact of load management can be double-edged. Substantial costs can be incurred in initiating a load management program, and if the program is not carefully designed, the implementation costs can exceed the benefits that are realized [1].

The success of any proposed load management program depends on whether the benefits outweigh the costs or not. Because of the wide variations in the shape and composition of load pattern curves among utility systems, as well as geographical variations in capacity and fuel costs, each utility is likely to make its own load management analysis.

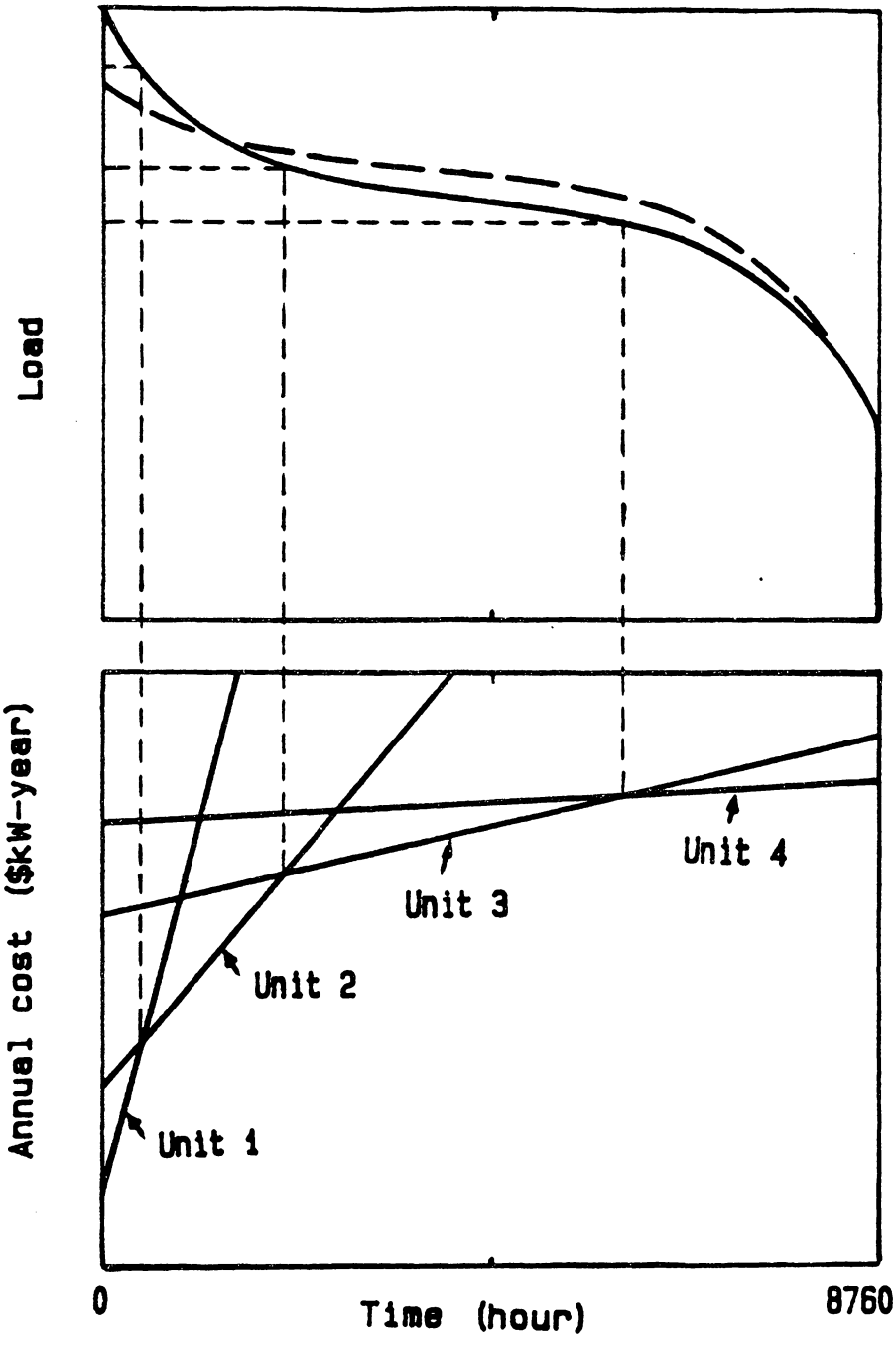


Figure 1. Reducing the requirements for peaking capacity using Load Management

1.3 Alternatives of Load Management

Four dimensions can describe the wide range of load management alternatives. These dimensions are:

- the intended program load shape objectives;
- the end-use categories;
- the underlying technology alternatives; and
- the mechanism of market implementation.

The first dimension involves the desired objectives or change in system load shapes. In the case of load management, there are three basic load shape objectives; Peak Clipping, Valley Filling, and Load Shifting. These load shape objectives are shown in figure 2. The load shape objectives reflect the desired end result associated with a load management alternative.

With the load shape objectives defined, the remainder of the evaluation process is directed toward selecting the method for achieving that objective. Naturally, the load shape objective for a utility can vary depending on the time of day, season, and time frame under study, and can also change as the utility's business conditions change.

The second dimension is selecting the appropriate end uses, whose energy demand and consumption characteristics can generally be matched with the requirements of the objectives. In general, any given type of end use (i.e., water heater or residential air conditioning) will exhibit typical and somewhat predictable load patterns, even though relative magnitude may vary. The extent to which these patterns match the utility's overall load shape is one of the major factors used to select an end use for load management programs.

The third dimension of the alternatives of load management is the selection of the appropriate technology option for each target end use. The selection process considers the

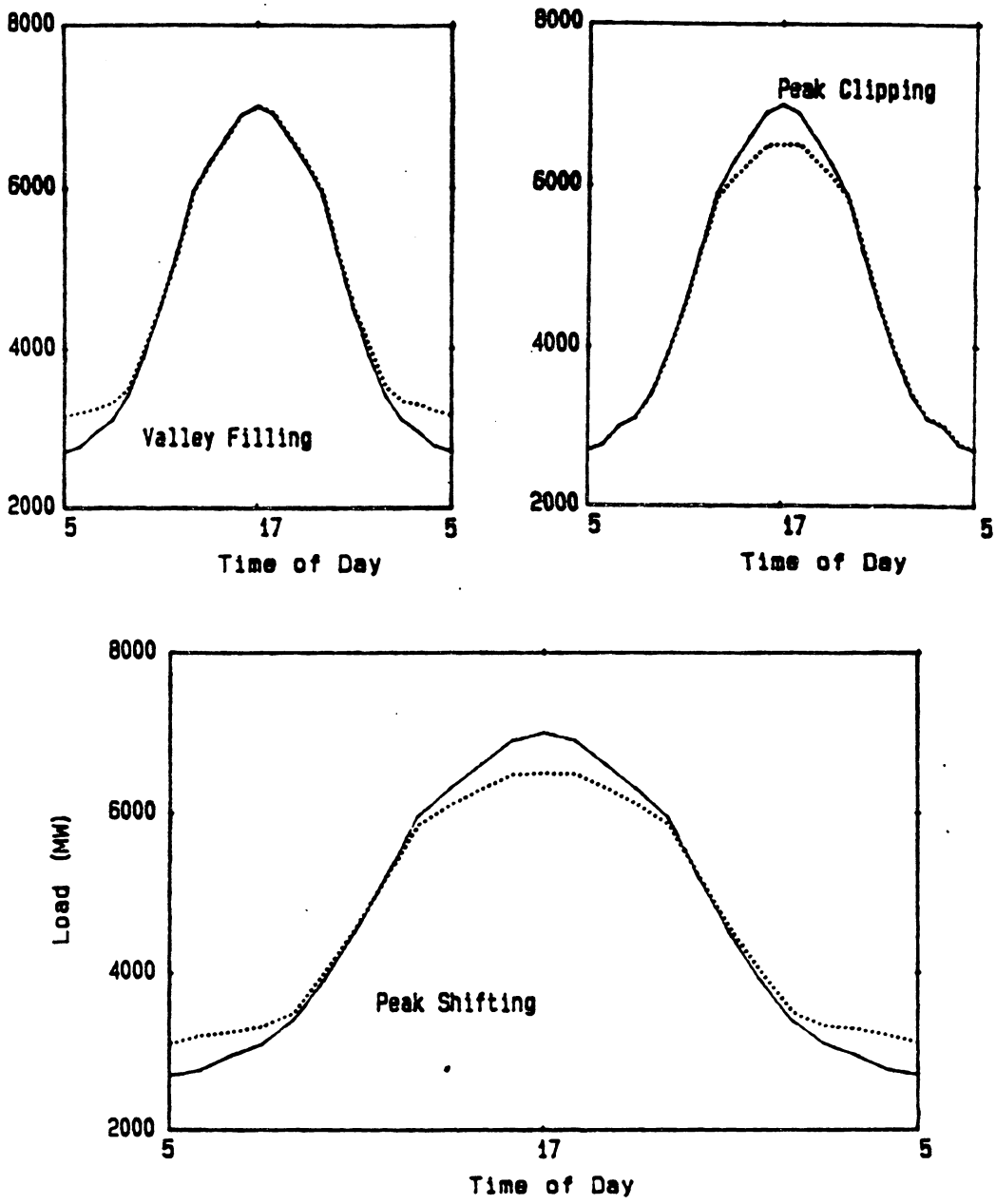


Figure 2. Load shape objectives of Load Management

suitability of the technology to a specific combination of the objectives and end use. Different desired objectives may require different end use technology options, while all of these options are suitable for the end use.

It is important to consider groups of alternatives because one option may produce a load shape impact that partially cancels the impact of another option. Furthermore, customers may independently implement options whose effects are inconsistent with utility load shape objectives. The selection process of the appropriate technology option can often indicate mutually compatible options that can be implemented together to increase benefits without substantially raising the cost.

Selection of the market implementation method is the fourth dimension of the load management activity. This process includes the selection of strategies to achieve the load shape modification benefits from the selected technology option. Market implementation methods vary for different options, but typical considerations include some form of market evaluation and promotion. Whether to contact the customer, offer incentives, or merely increase customer awareness of the availability of options, depends mainly on the behavior of the customer.

The implementation of a load management program requires an orderly method for considering the important factors that must be resolved in order to achieve the desired load shape. The following steps summarize this orderly method.

- Define the load shape objectives
- Decide upon the end use options to produce the required load shape
- Select the technology option that is suitable to produce the required end-use/load shape changes
- Design and implement the required program.

1.4 Peak Clipping

Peak clipping or the reduction of the system peak loads, embodies one of the classic forms of load management. Peak clipping is generally considered as the reduction of peak load by using direct load control. Direct load control is most commonly practiced by direct control of customer's appliances. While many utilities consider this as a means to reducing peaking capacity or capacity purchases and consider control only during the most probable days of system peak, direct load control can be used to reduce operating cost and dependence on critical fuels by economic dispatch.

Because of the high capital cost of new generating capacity, as well as the cost of the distribution system, most utilities charge for some type of "coincidental peak" demand. Coincidental peak demand refers to the customer's contribution to the utility's peak for the month. Therefore it is in the interest of the customer as well as for the utility to undertake additional demand-side management programs aimed at reducing demand during peak-load hours.

Since peak clipping is usually activated on days with probable system peak only, then the magnitude of this peak clipping impact is uncertain. However, for the customers purchasing their electrical energy from utilities charging for coincidental peak, the possibility of saving money by reducing their contribution to the peak is very high. The success of this process depends heavily on the ability of the customer to predict the exact time of the peak.

It is very important to note that reductions in the peak demand using direct load control are followed by increases in demand. This increase in demand is usually referred to by "payback" or "restrike" demand. The load control strategy must be selected carefully in order to avoid a shifted peak due to the payback demand. The following figure illustrates the idea of peak reduction and payback demand in the system load.

For the general electric utility curve shown in figure 3, if the peak was reduced by peak clipping methods then the electric utility will be affected by:

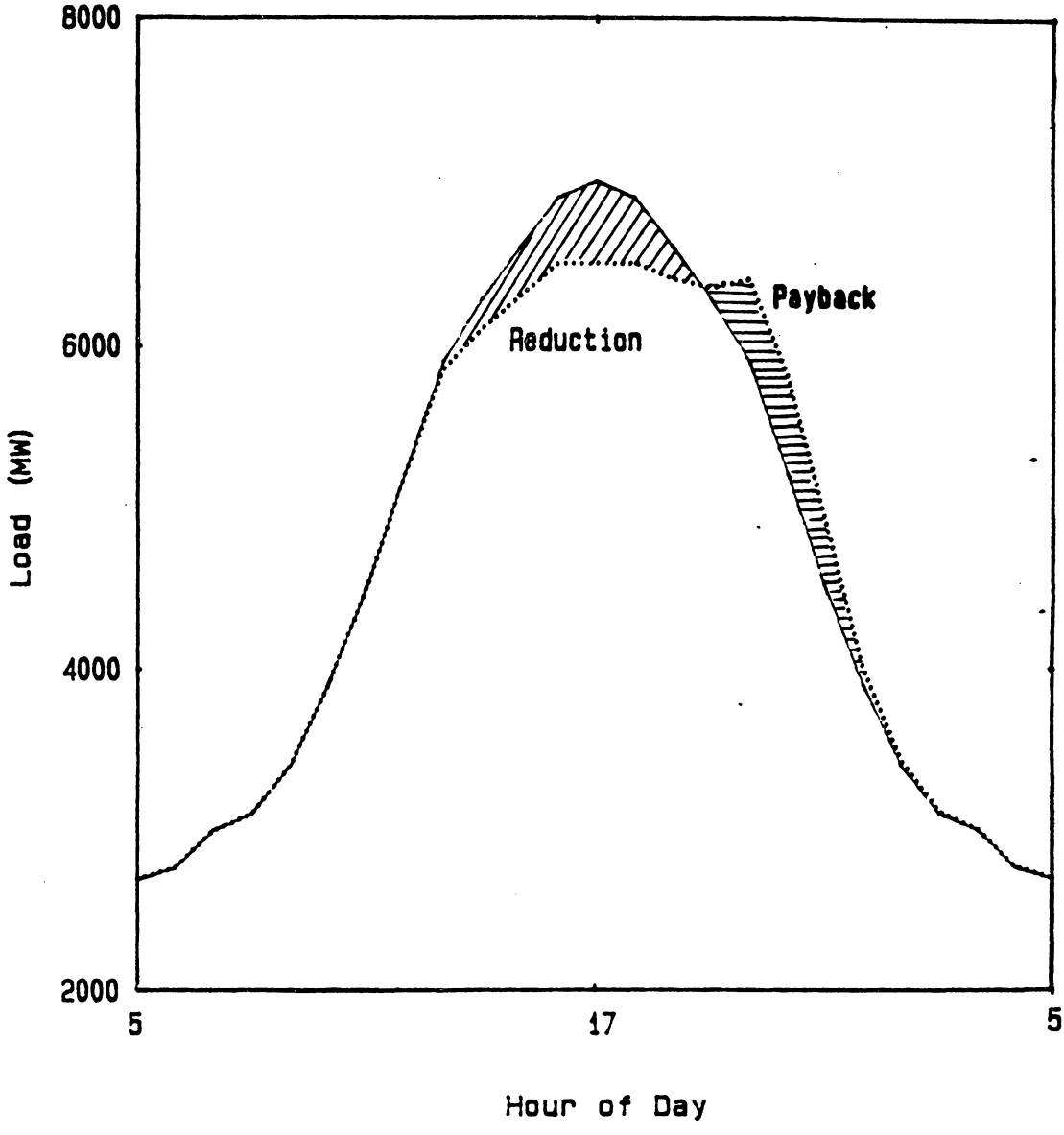


Figure 3. Peak clipping and payback demand

1. the peak load is reduced, requiring less on-line capacity to serve it. Further, if this reduction is constant over an extended period of time such as a planning horizon, then the additional capacity requirements are also reduced.

2. the average load is higher i.e., the load factor is closer to unity. The load factor is defined as:

$$L.F. = \frac{\int_{t1}^{t2} L(t)\, dt}{\Delta t \times Peak\ Load} \qquad (1)$$

where

Δt : time period and equals ($t_2 - t_1$)

L(t) : electric load as a function of time.

As the load factor approaches unity, the implications are:

- the generation, transmission and distribution system is more effectively utilized, thus improving the economics

- additional capacity requirements are reduced

3. if the increase in demand for energy due to payback was equal or greater than the reduction due to load control, then, more electric energy has been served than before. In most cases the opposite happens, that is there is a reduction in the total sales of electrical energy in days with load control

For existing load management systems, there are four methods which can be used to reduce the peak demand. These methods are:

- off-peak schedules;

- energy storage;
- demand limiting control; and
- computer demand control systems.

Off-peak scheduling applies to loads such as irrigation water pumps, which can be scheduled to operate at night or other times of low demand.

Energy Storage can also be considered to reduce on-peak demand. Water heaters can be operated off-peak and can store hot water for several hours. Buildings can be precooled at night (using the thermal mass of the building to store energy) to reduce daytime peak energy.

Demand Limiting Control can be designed to provide an indication of the demand and can open relays, preventing a pre-established limit from being exceeded.

Computer Demand Controllers can go a step further by projecting the load demand for the next demand interval, and if it appears that the demand limit (threshold value of the month) will be exceeded, automatically drop certain nonessential loads from the line. Once the demand decreases, these loads will be restored automatically.

The last approach will be considered for the design of the intelligent and integrated load management system. Significant developments in mini and microcomputers and the low prices of these equipment make this approach practical and economical.

1.5 Current Status of Computer Demand Control Systems

In the last 10 years many utilities have implemented computer-based load management systems. These systems have shown the capability to yield great savings in the control of peak demand electrical use. However, the existing systems still need great improvements in the areas of information transfer and decision making process. These systems exist in different

types and sizes. Most of them are used as load control systems, and range in complexity from a small microprocessor (for a single building), to a microcomputer for several buildings, to a "tree" distributed processing system employing a central minicomputer coupled to a number of remotely located microcomputers. The cost of these systems range from a few thousand to multimillion dollars. Figure 4 illustrates a sample diagram of a distributed processing load control system. This system was developed first for a large government facility in Idaho [2].

This type of system is a typical computer-based load control system. In this case, the system operator will feed the computer with all required information needed to dispatch direct load control including the time and strategy of the control program. System load and weather data and the short-term forecast for both will be fed by the operator too. From the system diagram, it is clear that the there is a one-way type of information transfer between the central utility and the system.

The other type of load management system is the forecast-based LMS. The Microcomputer Based Load Forecasting System developed for Old Dominion Electric Cooperative, Virginia, by Rahman and his associates [3] is an example of this type. This system has the capability to collect the required information for the generation of a short-term load forecast. This load forecast is used by the system operator to decide upon the need for load control to reduce the peak demand. If the forecasted load exceeds a predetermined threshold value, a warning message will be sent to the console terminal, to the printer, and to all users of the system. This message includes information about the magnitude and time of the new load peak(s). However, this system does not have the capability to decide whether or not to dispatch load control. Also, the load control system is a separate system, and it receives the information from the forecasting system through the operator. Similar to the previous type, this system has a one-way type of communication with the central utility. Figure 5 illustrates the schematic diagram of this type of LMS.

A study of these systems shows that there is no load management system at this time that has the capability of collecting the needed information, make decisions, and dispatch the

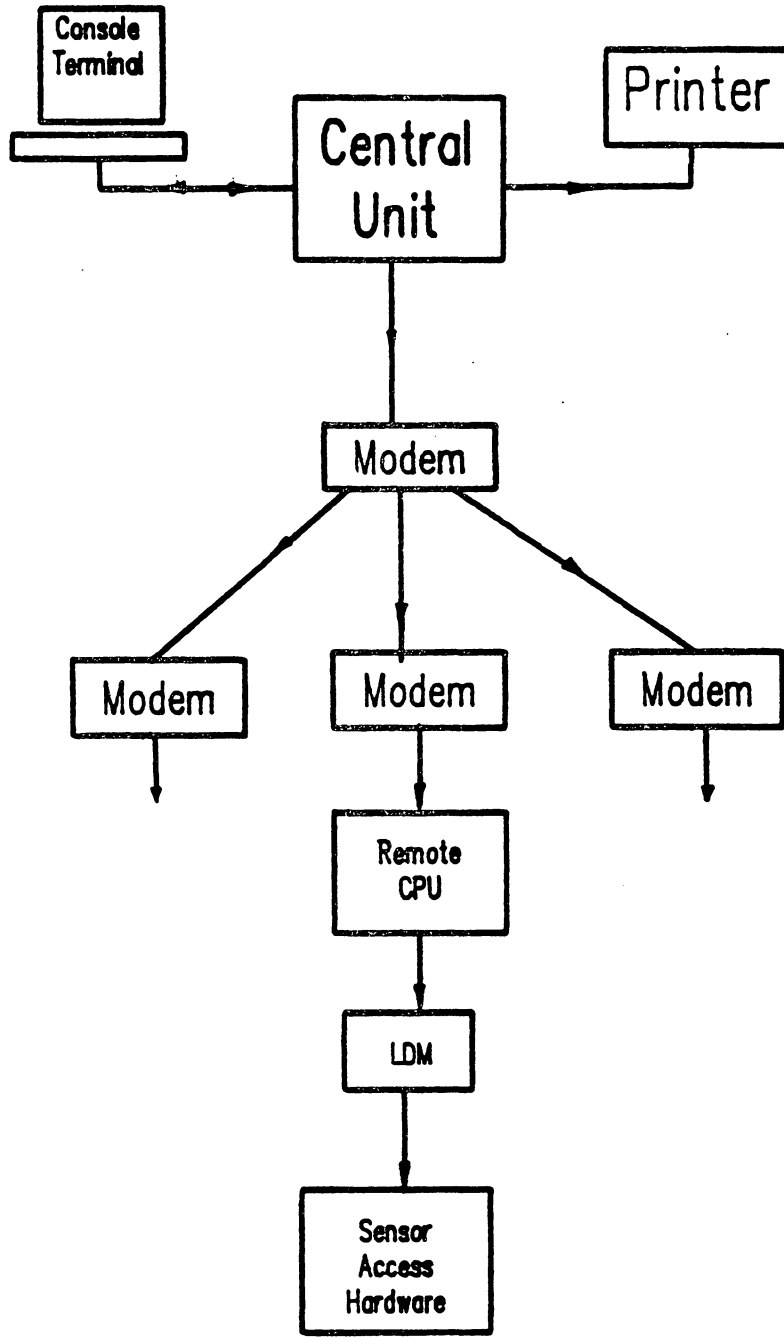


Figure 4. Schematic diagram of the load control center

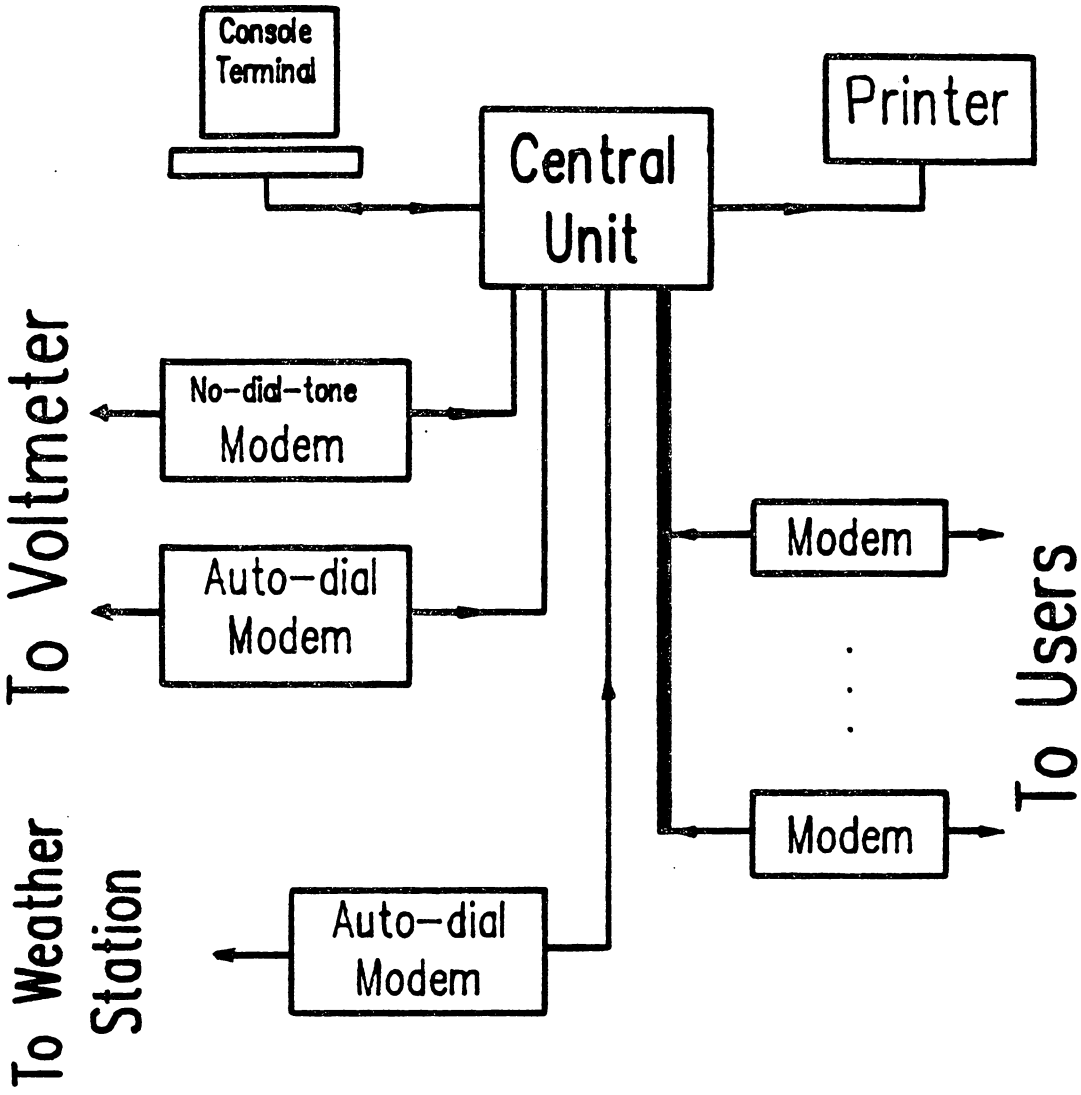


Figure 5. Schematic diagram of the microcomputer based load forecasting system

direct load control, all in an automated fashion. In general, the following may describe some of the major problems these systems still suffer from:-

- The control process is done manually in most cases by the operator of the system;
- The existing systems lack the capability to communicate with each other;
- There is a clear deficiency in the decision making process in these systems, and usually the decisions are made by the LM experts;
- Due to speed and storage limitations of the computers used in these systems, the employment of the traditional forecasting algorithms becomes impossible or impractical;
- There is a lack of information transfer between the LMS's and the electric utility, which makes each system unable to predict the activities of the other; and
- These systems do not exist as complete independent systems. In most cases, a load management system consists of several units connected to each other indirectly, and in general through an operator.

1.6 Need for an Intelligent and Integrated LM System

While existing energy management systems function well, they are not capable of communicating with each other or, more importantly, with the central system operated by the central utility. The result is that the larger opportunity of benefiting from the diversity of load is lost with exception of some manual efforts by the utility. Consequently the difference between the "peak demand" and "average demand" increases. Moreover, the integration of these systems in the planning process of the utility or the daily operation of the power system control center is almost impossible.

In this study, the use of information technology in developing a system for better communication and load distribution for use in the electric utility is proposed. This system

will be designed to take advantage of load diversity, and apply real-time control strategies for an efficient utilization of the generating sources. This system will apply the expert systems approach for the decision making processes and other functions which may require a high level of experience and knowledge. Also, this system will be designed so that it can transfer data and information to and from the central utility and other energy management systems that exit in the same utility.

Chapter II

DESIGN OF THE INTELLIGENT AND INTEGRATED LOAD MANAGEMENT SYSTEM

2.1 Objective of the LM System

The design of this load management system with its new features has many objectives and applications from the utility and the wholesale purchaser's of view. Even though the main objectives for designing this system was to provide a large customer (cooperative) with the means to reduce his share in the utility peak and hence reduce the cost of energy he is buying, but the integration of this system with the operation of the electric utility will provide new alternatives and solutions for some problems facing the electric utility industry. The load management system has great impact on different areas such as:

1. Economical Operations

   Load control can be used to displace high cost generation when the recovery energy after the power is restored to the loads (under control) can be provided at a lower cost.

2. Differed Construction of New Generation

   Load control can be used with other options of load management to lower the growth rate of peak load and defer construction of new generation facilities.

3. Regulating Increase in Demand

   In many cases, system load increases faster than generating facilities are able to respond. In these cases of fast load "pick-up", load control can be used to reduce the demand for electricity until generating facilities are able to supply the required power.

4. Emergency Load Shedding

   Load control can be initiated to help offset the effects of generation loss when no additional capacity is available.

5. Reduction of Generation Costs

   Load control can be used to reduce the peak demand in critical days where high cost generation is required to supply electricity to the customers. Such reduction may eliminate the need to run some of these generators or help in making these generators run at the highest possible efficiency.

2.2 Design Approach

The intelligent and integrated load management to be designed will be based on the concept of distributed control. The overall scheme is shown in figure 6. There will be a central computer with the overall responsibility of real-time data collection, communicating with remote computers, generating the system load forecast and determining the share of bulk load control for each major customer. An auxiliary microcomputer will be used as a front stage in the process of load data collection. The remote units, located at the premises of the major customers, will communicate with the central unit, poll the connected loads, generate

the local load forecast and execute the control action as dictated by the central unit. It is expected that, by providing the capabilities for two-way communication and intelligent local control, we shall be able to benefit from the diversity of load. Thus it will be possible to serve a larger number of customers using the same generating capacity.

The integrated load management function will be performed as a three-step interactive process. First a group of major customers including electric cooperatives (or the electric utility itself) will determine their share of load reduction if that is mandated by the central controller in response to an upcoming peaking emergency situation. Once the share for a major customer is known, the status of its customers' load will be looked into by the model. This is the second step.

Then, depending on the status and size of the loads, the model will determine which major customer will be required to shed how much load and when they will be allowed to relinquish load control. Once a major customer's share of load control is determined, then the third step will be initiated. At this time this customer will input that information into the energy management system for action. The central controller will monitor the load conditions of all major customers on a real-time basis and take corrective actions if there are any deviations from the plan. The forecast and control algorithms residing in the central computer will be based on expert systems and will be designed to respond to changing conditions on a real-time basis. This whole interactive process will be repeated as adjustments become necessary to meet the system constraints at each of the three steps.

2.3 Hardware Components

The central unit is based on an IBM-RT multitasking, multiuser personal computer. The fast execution speed (2 MIPS) coupled with availability of AIX and MS-DOS operating system makes this machine capable of carrying all of the functions including data acquisition, communication, data processing and data displaying.

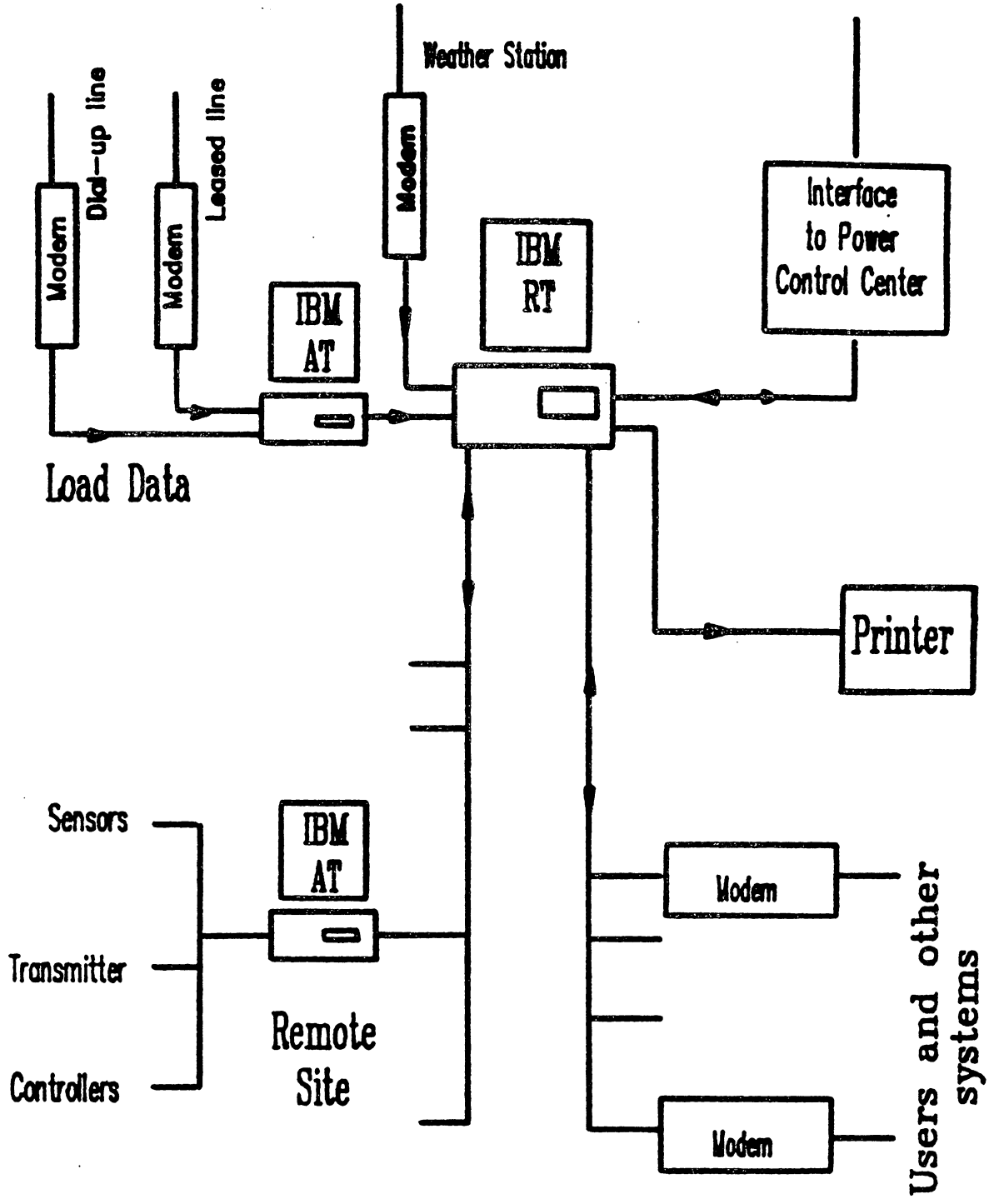


Figure 6. Overall scheme of the intelligent and integrated load management system

The remote units will be based on IBM-AT. This machine is used to transfer information back and forth with the central machine, receive orders from it, and send signals to its controllable loads.

2.3.1 The IBM-RT

The IBM-RT personal computer is the heart of the load management system where most of software resides. This personal computer is one of the most economical machines on the market, since it can carry the job of a minicomputer and at a relatively low cost. The standard machine can support upto sixteen (16) users on serial ports. Each serial port can be used for outgoing, incoming, or bidirectional calls. The system can support upto two parallel ports to be used for parallel printers.

RT PC is supported by the IBM Advanced Interactive Executive (AIX) Operating System, driven from UNIX System V, and selected enhancements from Berkeley UNIX. The multitasking, multi-user AIX Operating System has extensive compatibility with PC DOS, virtual memory manager and other optional rational database [4].

This 32-bit microprocessor based computer supports upto 4 MB of real memory (RAM) and up to 1 tetrabyte of virtual memory. Address space is managed by integrated memory management unit. Also, this machine comes with an integrated 1.2MB diskette drive that is compatible with the personal computer AT 1.2MB Diskette drive. Model 25 of the IBM RT comes with a disk storage of 70MB and can be expanded to 210MB with the addition of optional disk drives.

The selection of the IBM RT came after extensive study of several machines available in the market which can carry out the functions of the load management system. In addition to its unique features, such as the compatibility of AIX with PC DOS, a dollar-for-dollar comparison of this machine with other multitasking multi-user machines has shown clearly that it is the best available machine for the job. However, the support, software and hardware,

of the IBM RT has been found not as good as expected. Also, many of the huge programs developed by the manufacturer have been replaced by the author to satisfy the requirements of this project. The machine speed has been found to be as good as the manufacturer claims. However, the input/output access to the system storage (hard-disk) has been found to be slower than expected. The manufacturer claims that the new updated machines have higher I/O speed.

Different computer languages are available for the IBM RT. This includes C, FORTRAN, PASCAL and BASIC. For the special use of this machine, only C and FORTRAN 77 were employed on the system. These two languages come compatible to each other and to the operating system (AIX) and to the DOS shell. This compatibility is a very important characteristic for the requirements of this project, where each process can call any other program, execute any command, or even call another machine without leaving the original process regardless of the language it was written in.

2.3.2 The IBM AT

The IBM AT microcomputer is one of the most popular microcomputers on the market. A 16-BIT 80286 microprocessor is the heart of this machine. This machine can be used as a single user, single tasking machine when operated by DOS 3.1 Operating System. XENIX Operating System can be used also on this machine to convert it to a multitasking multi-user system. Some software is available in the market to convert this microcomputer to a multitasking machine only when run under DOS 3.1. This includes packages such as WINDOWS, QDESK and TOPVIEW.

For the special application of this project, the IBM AT will be used as a front-end process for data collection. Also, it will be used as the heart of the remote site controllers. For the first application DOS 3.1 will be the Operating System, while XENIX will be used for the second

application. Quick BASIC has been used for developing the required software for the data collection process, while FORTRAN and C were used for the remote site applications.

2.4 Functions of the Load Management System

The Load Management System (LMS) activates several functions continuously or at regular intervals in order to achieve its objectives. Most of these functions involve certain processes during which some decisions are made. The major decision, of course, is when and how to dispatch direct load control in order to reduce the system peak load. Informing the operator and other users of the system about the current status of the system load and the activities of the LMS is another function of the system.

To minimize the need for human intervention, it was essential to design the algorithms and to select the suitable operating system and computer languages for the construction of the system. This must enable each process to call another, sending warning massages to terminals or printers, and make calls to other systems. This means that the design must be made on the assumption that the system will work 24 hours a day without human intervention. This does not mean in any case that the system operator does not have full access to the system. Actually, the operator has the ability to modify, cancel, or force the activation of any process in the system.

The major functions of the LMS can be divided into two sets: central unit functions and remote-site unit functions. The functions of the central unit are much more important than those of the remote site and include certain processes that require intelligence and experience. For this reason, expert systems and rule-based programs were the major tool for the development of most of these functions. Functions of the remote-site units usually include data transfer and the dispatch of direct load control.

2.4.1 *Functions of the Central Unit*

The central unit has the major role in the load management process. Functions of this unit include on-line processes, off-line processes and processes that run under the request of certain programs or by the operator. Most of the data and knowledge base exists in this unit. Also, most of the decision making processes reside on this part of the system. A summary of the major functions of the central unit is presented in the following.

- Data and Information Processing: this includes four main processes, data acquisition, data management, data retrieval and data analysis. Load data, weather data and information from other systems form the core of input to the system. The operator also has the ability to add, delete or modify any archived data on the system.

- Load Forecast: a rule-based load forecast algorithm is developed in order to supply the projection of the power demand for 1 to 24 hours lead time. This algorithm has been used as an alternative to the traditional time series programs which require mainframe computers. The available results show that this algorithm can supply short-term load forecasts with high accuracy. Moreover, this algorithm can use on-line information from other processes on the system or other systems to produce an accurate forecast.

- Modelling of Load Characteristics: mathematical and logical models are required to represent the characteristics of the controllable loads used by the system. These models are used to

    1. determine the normal diversified load characteristics of the water heaters and air conditioners;

    2. determine the impact of direct load control on the load characteristics of each of these devices; and

3. determine the effects of different control strategies on the load characteristics.

- Direct Load Control: this decision making process will be used to determine

  1. whether or not to dispatch the direct load control based on the information supplied by the load forecast;

  2. when and how to dispatch the direct load control under the operator's justification; and

  3. the best control strategy for that specified day.

- Alarm System and Information Display: different kinds of information displays will be available to the operator and users. On-line warning signals informing all users of major activities on the system will be provided. Alarm signal with proper messages will be sent to the operator in cases of hardware or software problems.

The following chapters will discuss in detail some of the above mentioned functions.

2.4.2 Functions of the Remote-Site Units

In most cases, the remote site units are idle and waiting for commands from the central units. These commands include the request for information or an order to dispatch load control. These functions can be summarized as follows.

1. Data transfer with the central unit: the remote site computers have the ability to transfer some information about the controllable loads of that area. Meteorological data can be transferred to central units to assist in the decisions related to dispatching of load control. Data transfer can be done on a regular basis or upon the request of the central unit.

2. Dispatch of direct load control: when the management system decides to initiate the load control process, it sends information to each remote-site unit concerning the time, period, size, and type of loads and strategy of load control. When this signal is received by the remote-site unit, certain processes will be activated in order to apply the required work.

2.5 How the LMS Works

The load management system keeps track of changes in the system load. On-line readings of the instantaneous system load are obtained, filtered, averaged and archived for 24 hours a day. The collected data will be used to forecast the system load for the next 24-hours. If the forecasted demand at a certain hour (or more than one hour) of the day will exceed the monthly peak (so far) and a certain threshold value, then the forecasting algorithm will initiate the load control algorithm. The load control algorithm, based on certain rules, will decide whether to dispatch load control or not. If there is a need for load control, the control algorithm will call the load models to get them required information about the on-line loads at the time of control. Also, the load models will provide the control algorithm with the predicted payback that will follow the control process. The control algorithm will decide upon the optimum load control strategy that satisfy as much of the requirements and constraints as possible.

When the time of predicted peak comes, the central unit will send signals to the remote sites to start load control. These signals usually include the type of loads to control, the time to start the load control, the number of load blocks to include, the period of control, and the control strategies to be used. When the remote-site units receive these messages, radio signals will be sent to the loads included in the program to switch them off or on. After the required control period passes, all loads will be restored on-line.

The flow-chart shown in figure 7 illustrates the procedure of dispatching load control. Other activities will be included in this process, such as sending alarm signals to all users and

to the system operator informing them about the predicted peak and the plans for load control. Also, information transfer will be done between the LMS and the utility controller and other load management systems in the utility. This process is done to guarantee that there is no contradiction in the control plans of the LMS and other systems.

The operator has the upper hand in the whole process. He can use his experience and judgement to alter the plans of the LMS. In many cases he may decide to cancel the control program for a certain day, or in other cases to force the initiation of load control even if the LMS does not find a need for that. In many cases when the system is not attended, the initiation of load control is restricted to the approval of the system operator. Such options have been made in order to avoid any activities of the system when there is a possibility of malfunction of some units of the system at times when there is very little possibility of having a peak load, such as nights or weekends.

The following chapters include detailed descriptions of the major functions of the system, the method used to develop the algorithm and some of the results. These results have been obtained by simulating the actual behavior of the system using real data from previous years.

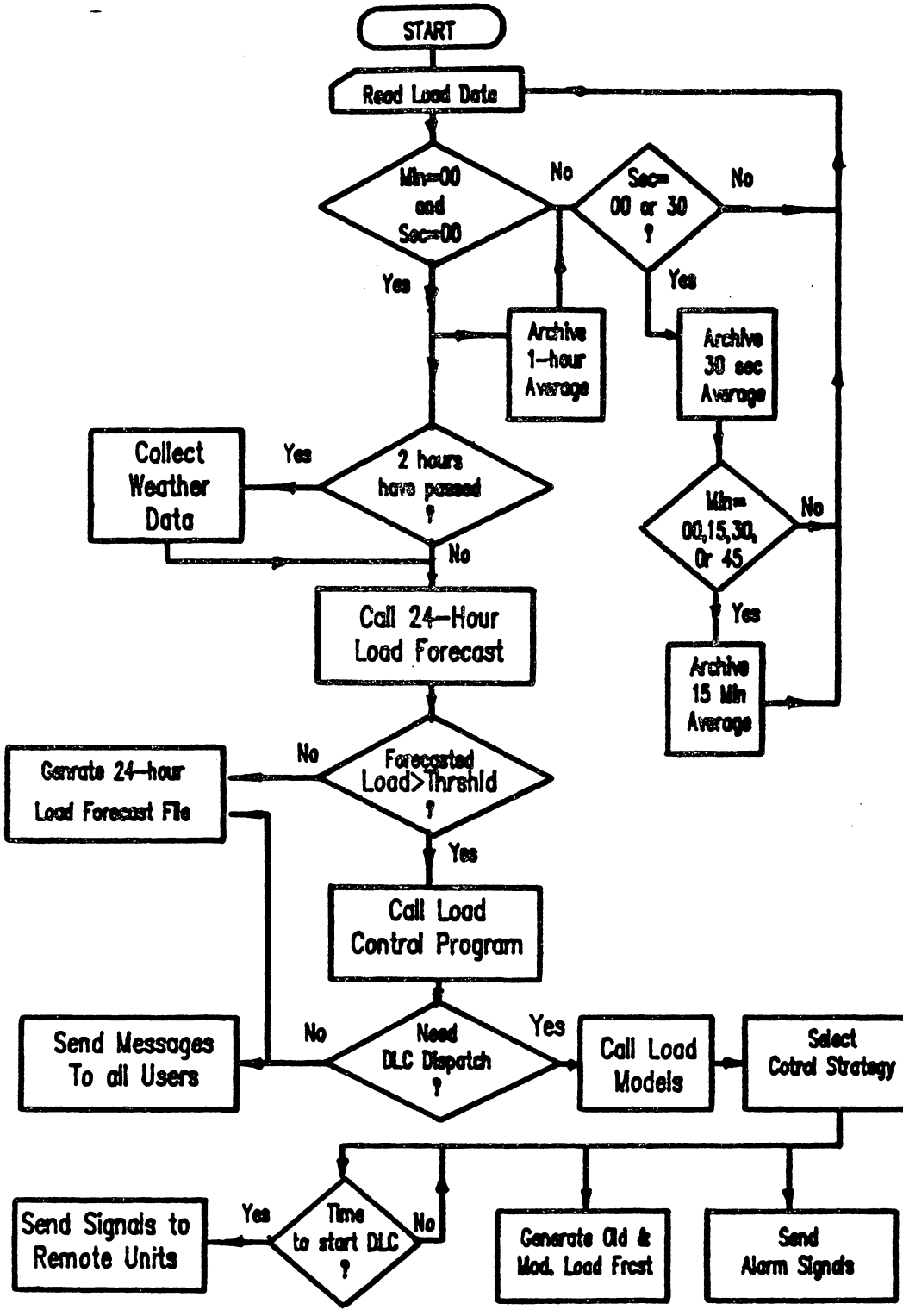


Figure 7. Flow-chart of the functions of the load management system

Chapter III

DEVELOPMENT OF DATA BASE AND INFORMATION CENTER

The basic function of the information center of the LMS include four processes; data acquisition, data management, data retrieval and data analysis. Rule-based techniques will be used to enhance the performance of the information center of LMS. Figure 4 illustrates the structure of the information center.

The important characteristics of the four processes can be summarized as follows:

- Data Acquisition: which is the process used to enter data to the main database. This data is collected continuously (i.e., load data) from remote transmitters, on a regular basis (i.e., weather data), and manually by the operator. The form of input in these cases may be through modems, hardwired connections or terminals.

- Data Management: the process of storing the data and preparing it for easy retrieval. This process includes data filtering, on-line storage and off-line archiving of the data.

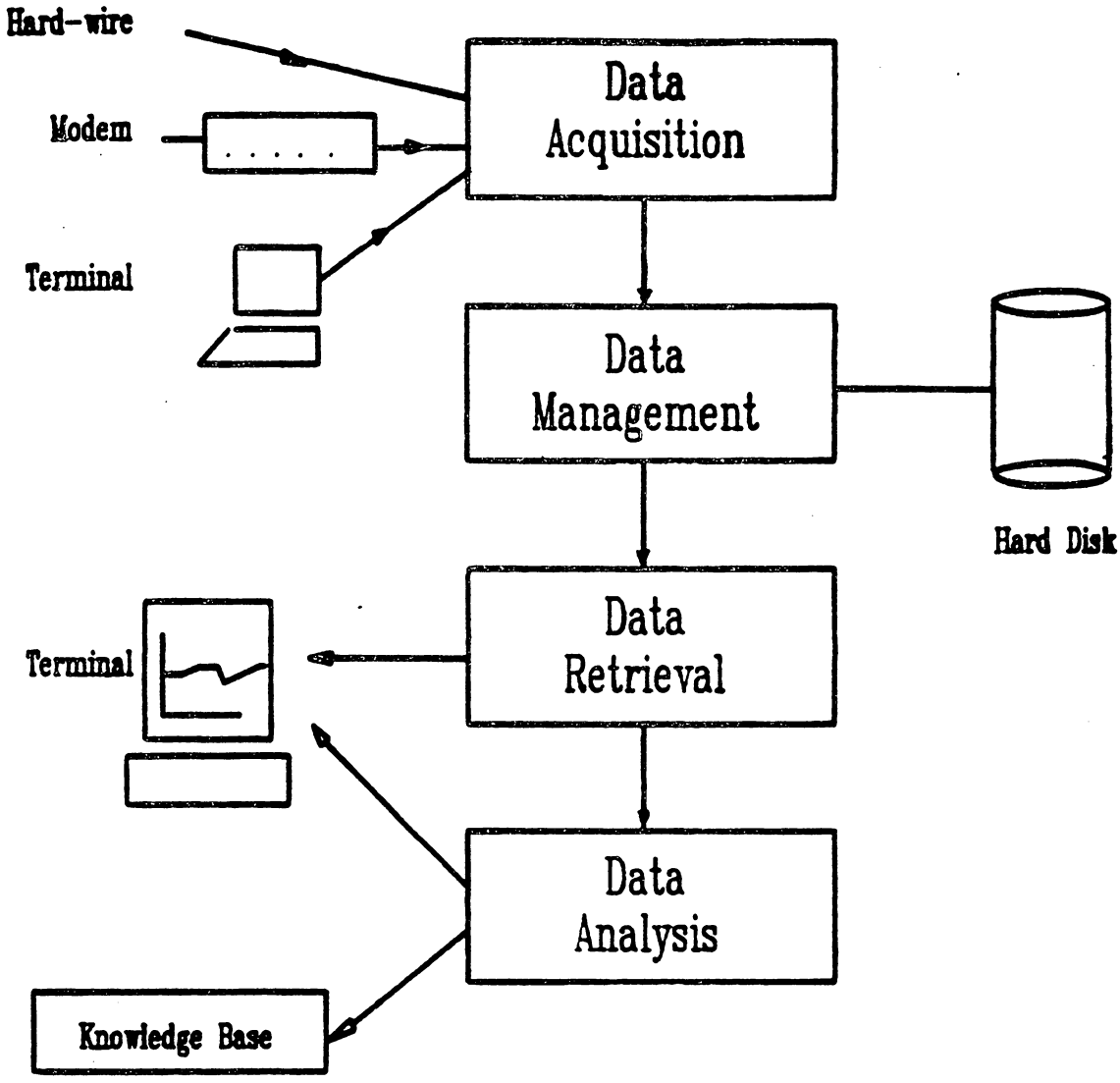


Figure 8. Processes of the information center

- Data Retrieval: the process of locating and presenting the data in response to requests from users. This process includes low and high detail search through the database. Figure 9 shows the information display supplied to the user in response to his request about load data for the last 24 hours.

- Data Analysis: the process of deriving new rules from the information available including statistical summaries.

The development of database, rule-base, and display information are presented in this chapter. This chapter will discuss the following:

- Data Collection Process;
- Development of Rule-Base;
- Creation of Information Displays;
- Generation of Alarm Messages, and
- Final Database.

3.1 Data Collection Process

Data collection is one of the major functions of the load management system. Important information will be collected through three channels.

- hardwire connections;
- dial-up phone lines; and

24-Hour Load Data

Hour	Load (MW)	Hour	Load (MW)
20:00	6823	08:00	6827
21:00	6598	09:00	7297
22:00	6439	10:00	7301
23:00	6265	11:00	7599
00:00	6213	12:00	7449
01:00	5838	13:00	7239
02:00	5647	14:00	7087
03:00	5650	15:00	6935
04:00	5701	16:00	6878
05:00	5902	17:00	7016
06:00	6011	18:00	7191
07:00	6352	19:00	7430

Date: 2/17/1987
Time: 19:15:30

Figure 9. A sample display on a user terminal about 24-hour load data

- manually by the operator.

Leased lines can be used for the first method, where special modems can be used to collect data through dedicated phone lines (no dial tone) from remote sites. For the system under discussion, this method is used to collect the total system load at the rate of 150 readings per minute. A voltmeter transmitter with a special modem can be installed at the generating side of the utility to measure the instantaneous reading of the system load.

Dial-up lines can be used to collect data through autodial modems at regular intervals. Special software programs are required to make the phone call and dropping the line when data collection is over. Usually this method is used to collect data from another computer. Comparability between operating systems on both computers is not necessary, however, communication parameters must be the same at both ends of the line. An example of data collection through dial-up lines is the collection of weather data from the weather station computer. The central unit of the load management system calls the computer of the weather station at regular times every data to collect the most updated meteorological data.

Operators, also, can enter data to the system through terminals or the keyboard of the console. In this third method of data collection, the entries of the database can be modified, deleted or added to the system. In the load management system, rules and factors needed for some rule-based functions of the system are mainly the type of information operators are interested in updating or modifying.

The following sections of this chapter will discuss in detail how the system collects data from different sources. Filtering, archiving, analysis, and knowledge extraction of the collected data will be discussed too.

3.1.1 Load data collection

As shown in figure 10, a voltmeter is used to read the instantaneous value of the system load. This voltmeter sends the collected data to a transmitter which is connected to a special modem (requires no dial tone) to transmit the digital readings to the load management system

at the rate of 150 readings per minute. On the side of the load management system, a similar modem connected to one of the serial parts of the IBM-PC-AT (or the IBM-RT) is used to receive the data transmitted over the leased line.

The voltmeter reading corresponds to the total generation of the system. This value may differ from the value of the system load because it is impossible to accurately match the load with generation. Comparing measured data of the total system generation with the actual system load of Virginia Power has shown that the difference ranges between -100 to +100 MW for the hourly load average.

3.1.1.1 Filtering of Load Data

Collected load data will be filtered by passing it through a software filter which rejects bad data. Since the system collects data at the rate of 150 readings per minute, the rejection of few inputs will not affect the accuracy of collected data.

The filtering process checks for bad or unexpected characters in the received data, and whether the value of that data is in the acceptable range or not. The voltmeter transmits the readings in the format "+##.###", and "#" represents a digit between 0 and 9. The received data will be rejected if:

- number of characters in the reading is not equal to 7.
- if the first character is not "+" or the fourth is not a ".".
- if any of the remaining characters is not a digit (0-9).
- if the value of the reading differs by more than 500 MW from the average during the last 15 minutes.

This filter will insure that the data transmitted to the second level of data collection is error-free. However, errors might exist in very few cases because of memory faults and/or

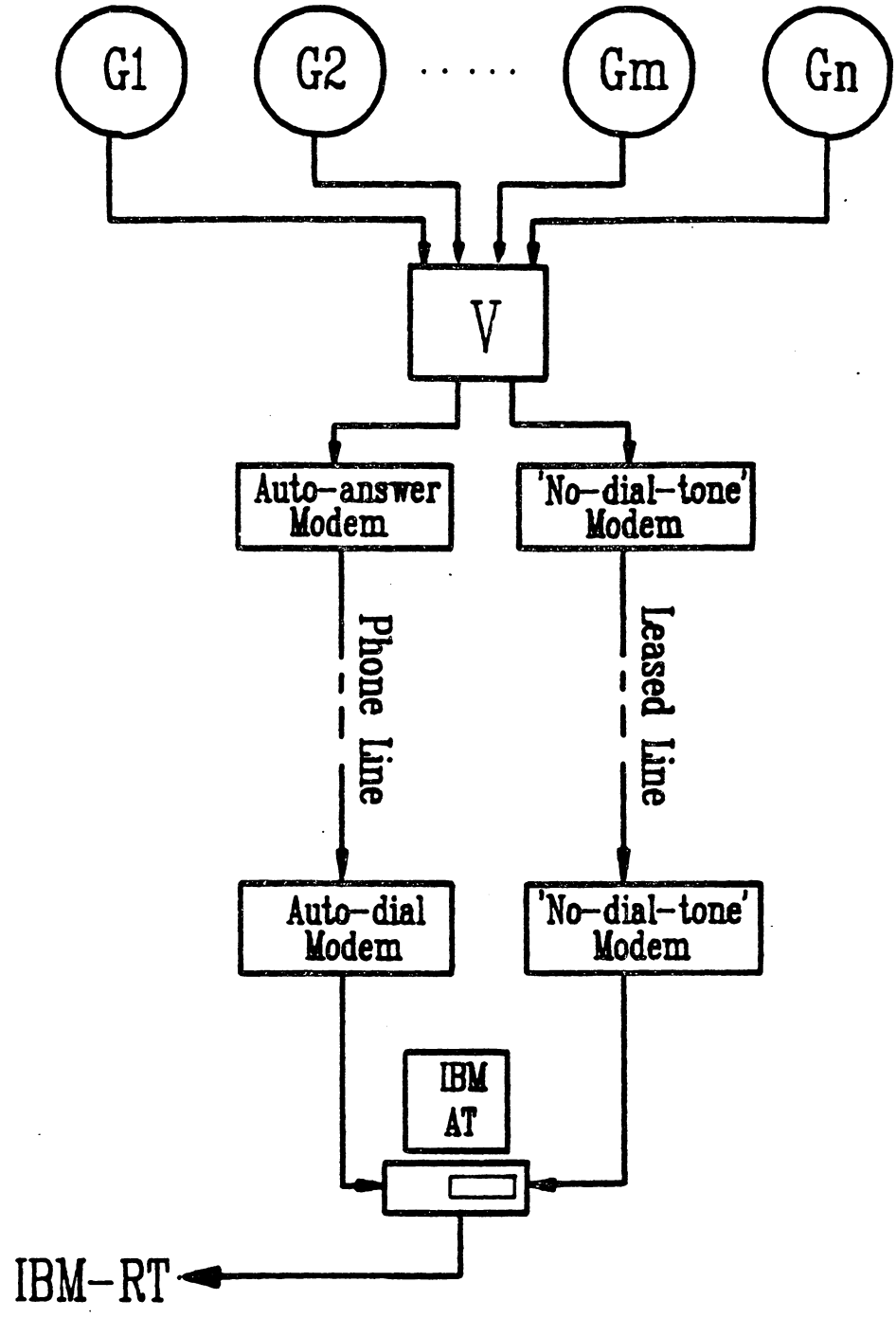


Figure 10. Reading instantaneous load data from the generation side

read/write errors on the hard disk. Such errors can be corrected by the operator, and may require hardware maintenance if they happen very frequently.

It is important to note that another type of bad data can be received because of hardware problems in the voltmeter or any of the modems. In such cases, these equipments may transmit data that is good in its format but bad in its value. If this value is in the range of the acceptable data then it will pass the filter and get archived. It is the duty of the operator to keep an eye on the collected data and be sure it matches the actual load value of the system.

3.1.1.2 Archiving of Load Data

After the load data gets filtered, it will be averaged on a 30 second, 15 minute, and one hour basis. For each of the three cases a well-formatted 24-line file will be created and updated whenever new averaged data arrives. In addition to that, the hourly averaged data will be saved in the on-line database which is used by different functions of the system. At midnight, the 24-hour load data will be added to another monthly data file which includes all hourly data for the whole month.

3.1.2 Meteorological Data Collection

Meteorological data collection is done by calling the computer of the weather station and transferring the data file containing the required information. In most cases the weather station updates its files every two hours. For this reason the LMS will call every two hours to collect the most recent weather forecast plus the actual readings for previous hours.

Since the Operating Systems of the machines of the weather and the LMS are not compatible, a computer program written in C and AIX was developed to emulate the Operating system of the other computer. After the required data transferring is done, a signal will be sent to the modem to drop the line. If the call failed for any reason, the system will try two more times. If it fails, a warning message will be sent to the printer and the operator terminal

(console). However, if no corrective action was made, it will keep trying every two hours to make the phone call.

Penril, Hayes and compatible autodial modems are defined in the software for weather data collection. The baud rate and other settings are chosen based on the protocol of the sending and receiving computers.

The collected data will be archived in its format in the system for further use. Also, some of this data will be transferred to the on-line database. The actual meteorological data for any day will be archived in a monthly file at midnight every day.

3.2 Data Management

After the collection of data, the system will decide how to use it. Some of it must be used immediately, some later on, and some will never be used. Also, some of it needs to be archived temporarily while others permanently. In general, the data management process will

1. Decide when to use the data;

2. Whether the data will be archived or not;

3. What data need to be made available for display for users; and

4. When to erase the archived data or eliminate part of the database.

Archiving is done by sending certain information to one or more of the data files or databases. Certain modifications can be done on some of the elements before they are sent to their final destination. For example, the load data will be averaged on an hourly basis before it is sent to the monthly load data file and the on-line database. For weather data, THI

(the Temperature-Humidity Index) will be calculated using the dry-bulb and dew-point temperatures. Also, averaging for the temperatures of the stations (three or more) in the service area of the utility is done before the data is sent to the database.

In many cases temporary files will be created for transferring some data from one process to another. Such data files include the creation of the normal diversified demand of a certain load in order to use it by the load control program. Small files including messages, dates and times are also created to assist the process of putting all functions together and enable them to work in harmony.

3.3 Data Retrieval

One of the major objectives of the information center of the LMS is the creation of intelligent databases that enables the user to retrieve the required information simply and quickly. For this purpose, certain programs have been created to retrieve the data from its source files and display it on the user terminal on request. Such activities include the displaying of summaries about the 30-second, 15-minute, 1-hour load data, 24-hour load forecast displays, weather summaries, and the information about daily and monthly peaks. In some cases the display has a format that is different from any data file on the system, because the sole purpose of it is to make it easy for the user to understand the information he receives.

Data retrieval is not an activity of the operator only, but it can be made by most processes. As it will be seen in later chapters, some algorithms are activated at regular times, or upon meeting certain conditions to retrieve old data for the purposes of data analysis, or to create a new data file. The self-revising mechanism of load forecast program is a good example of this. In this algorithm, information about the load forecast for previous days will be retrieved for the purposes of analysis. The load modelling process includes the

retrieval of some information about different factors affecting the load shape of certain equipment.

Data retrieval does not involve in any case, the modification of the data sources themselves. In some cases the data itself is modified while it is being displayed or transferred to another file or process. In certain situations, the source data file can be eliminated after the data it includes has been processed. The temporary data files, used to transfer data from one program to another, are examples of such files.

3.4 Data Analysis

Data analysis usually includes the process of creating the knowledge-base (sets or rules), extracting the relationships, and/or creating of graphical and statistical representation of the data. This process is done automatically by the system itself or upon the request of a user. When the data analysis procedure is activated, the data retrieval procedure will be initiated automatically. If the data analysis is activated by a user, in most cases the output will be sent to the terminal or to the printer, while if it was initiated by the system itself, it will be sent to the hard disk or memory. Few exceptions such as the analysis of the load forecast may lead to the transmission of warning messages to all terminals and printers on the system.

Chapter IV

LOAD FORECAST

The problem of short-term (one to twenty four hour) load forecast in the electric utility industry has received extensive attention in the last 15 years. Forecast algorithms developed in response to this need almost exclusively fall into the category of time series approaches [5] to [20]. Rahman and Bhatnager [21] provide a comprehensive discussion on this topic including the performance of some of these algorithms. These algorithms are generally characterized by large database and high computational time requirements. With a view to developing an alternative algorithm which might yield improved accuracy with smaller database, and reduced computational requirements, Rahman and Bhatnager [21] have presented a knowledge-based short term load forecasting technique. With this technique the database requirements can be reduced to one month. The success of this approach , however, depends on the existence of some historical days with similar load and weather conditions. Also, in this approach, changes in load are related to the type of day (i.e., season and day of the week) and the expected weather conditions. Thus the effect of direct load control on the load forecast is not easily identifiable.

The present study has used some of the features of the knowledge-based algorithm previously reported. However, this new approach differs significantly in its way of defining the rules, extracting the relationships, and even the mathematical formulation of the problem. Moreover, in this work it is intended to draw upon the additional insights gained since the other algorithm has been put on-line more than one year ago. Some of the major considerations that have guided the development of the present algorithm include the following.

1. Perform as much off-line computations as possible;
2. Use only one week of historical load and weather data for on-line computations;
3. Provide automatic rule updating features;
4. Keep on-line computations to a minimum so that personal computers can be used for on-line forecast; and
5. Implement the algorithm in such a way that it is easily transferable to other PC's or mainframe computers.

The forecast algorithm that has been developed and implemented in response to these requirements is discussed in the following.

4.1 Forecast Algorithm

The forecast algorithm is based on emulating the knowledge, experience and analogical thinking of experienced system operators. It also uses relationships that exist between day-to-day load and weather conditions. The author has attempted to identify variables and rules that are used by experienced system operators in estimating or forecasting the system load, and the criteria for employing different rules in different situations.

This section provides a summary of the algorithm developed for 1 to 24 hour load forecast for an electric utility. The knowledge base is the (electric utility) hourly load data for 1986 which is used to extract relationships between expected and historical load, and between load and weather conditions. The on-line database is limited to one week's hourly load, ambient temperature, dew point temperature, and wind speed. To minimize the on-line computational requirements for the ensuing 24-hour forecast, a reference day is chosen from the database along with a set of rules which are based on expected weather conditions. The similarity of weather conditions between the chosen historical day and the target day is not essential for this algorithm to work. A rule revising mechanism is built into the algorithm such that the pre-selected rules and factors can be modified if the average of the peak forecast errors is larger than 3% for three consecutive days. This feature is specially useful during the days of season change-over. The 3% threshold value for initiating the revising mechanism was selected after testing different threshold values and it was found the best value for this purpose. 2%, 2.5%, 3%, 3.5% and 4% threshold values were tested and it was clear that the 3% value can produce better results. Using smaller values will cause the program to initiate the revising mechanism very often, even at times it is not required to modify the rules or factors.

4.1.1 Developing the Database

One of the most important characteristics of the rule-based algorithm is its minimal requirements of on-line historical data. The database used for this algorithm consists of one week of load and weather information for the last seven days including the current day. This database is updated once every hour with the new hourly load data, and every two hours or whenever an updated weather forecast is available.

In order to maintain the size of the database, the data file is scrolled up at midnight every day to eliminate the data of the oldest day. The load and weather forecasts for the new

day are inserted at the end of the file, and are replaced by actual data when it becomes available.

For each hour of the week, the values of the system load in MW, dry-bulb temperature in °F, dew-point temperature in °F, and wind speed in mph are available in the database. Other weather parameters are not archived in the database of the load forecast program because they have no or relatively minor effect on the system load as it is shown later.

4.1.2 Selection of Reference Days

The load forecast algorithm presented in this study is required to have a basic load curve which can be selected as the approximate forecast to start with. Previous investigations have used a curve which is an average of several (3 or more) load curves for previous days selected from the database. In this study, the author has investigated this approach and found that it lacks the accuracy needed for the preliminary curve. The reason is that the load shape keeps changing as the weather conditions change and as the time of the season keeps moving. For this reason, the author has generated hundreds of graphs comparing the load shape of many days in the four seasons and some selected days. For example, the load curve of a certain day was compared with the load curve of the last seven days, the last three similar days in the last three weeks, the average curve of those three curves, and the day with the closest weather conditions in the last two months or same time in the previous year. From these comparisons, it was very clear to the author that whatever the differences in weather conditions the load curve for the previous weekday has the closest shape to that of the forecasted day.

This conclusion was very clear for Spring and Fall where there is no constant load shape. In these two seasons, the load curve keeps changing from the typical load curve of winter to the typical load curve of summer.

This general rule is correct for all working days except Monday. Also, this rule is not accurate for the case of Saturday, Sunday and Holidays. For this reason, the previous procedure was repeated for these three days in addition to the holidays. This could lead to the conclusion that for Monday the last Friday has the closest load curve. Also, for Saturday and Sunday the same day one week back can be the best selected day for this purpose. For the holidays, the load shape of last Saturday can be used as the best approximation to start with.

Two important phenomena were noted during this study. First, the load curve of any day will be raised up or down in the early hours of the day as an inertia of the previous day regardless of the differences in temperature. Second, Monday and Friday have certain hours that the load curve is higher than the typical curve of the working day. Early hours of Monday and late hours of Friday show such phenomena.

4.1.3 Off-Line Calculations

An effort has been made to make as much off-line calculations as possible. The reason for this is to minimize the run-time of the forecast program on the microcomputer, and at the same time, reduce the historical database requirements. The main objective of off-line calculations was the examination of rules and relationships between electric demand and variables affecting this demand. Most of these variables are meteorological conditions, such as temperatures, humidity, wind speed, solar insolation, cloud coverage and also time of the season.

The historical data of 1986 was selected for this purpose, where the hourly demand of Virginia Power Company with actual meteorological hourly data for all variables above were available. In order to define the relationships between each variable and electric demand it was essential to isolate each variable by fixing all other variables. Even though this is impossible to be done on actual data, but it was practical to select days for each season with

similar conditions except one. For each season of 1986, several sets of days were selected where one meteorological condition is varying.

The first step in this process was the investigation to see if there is any kind of correlation between load data and the varying conditions. To do this, the MINITAB [22] statistical package was used to correlate load data and each variable. Linear, polynomial, and exponential correlation studies were made for each variable. From this step the following conclusions were made.

1. For Summer, late Spring, and early Fall there is some correlation between humidity and system load. In another effort, the relationship between the changes in demand and changes in THI were studied. THI (Temperature-Humidity Index) measures the combined temperature-humidity effect on humans and their feeling of comfort or discomfort when subjected to different temperatures and humidity values. In engineering, this combined index is referred to as "effective temperature". THI is calculated through the equation

$$THI = 0.55 \times T + 0.2T_d + 17.5 \quad (1)$$

where

T = Dry-bulb temperature in °F

T_d = Dew point temperature in °F

This study has revealed that the factor between system load and dry-bulb temperature is larger than that with THI when the ambient dry-bulb temperature is higher than 91°F or lower then 76°F. One explanation could be, that for the utility service area studied, the air conditioning load appears to saturate after a threshold value of approximately 91°F. At that temperature level, during summer season, it is almost always humid and air conditioners always run during the daytime. Since the load forecast is based on an on-line data-depth of one week, and there is no perceived variation in humidity during this time, this parameter is already built into the rule-base. For winter, it was very clear that there is no effect of humidity on the demand for electricity.

2. Wind Speed. For winter it was found that there is an increase in demand in days with high wind speed and very low temperatures. However, for summer, no correlation between changes in wind speed and the load was found.

3. Solar Insolation and Cloud Coverage. It was found that there is a very weak relationship between electric load, solar insolation and cloud coverage even in winter. Furthermore, the number of houses with solar heating and/or cooling are very limited in the utility service area studied.

4. Temperature. The correlation between electric demand and dry-bulb temperature was found to be very strong. It was clear there is a direct relationship between the increase in temperature in summer and the increase in electric demand. Similar, but reverse relationship was found for winter. Fall and Spring has the same kind of relationship but varies between Summer and Winter in proportionality.

5. Time of the season. It was found that changes in weather conditions have different effects on electric demand for different times in the season. Strong and direct relationships can be found for days in the middle of the season, while minor effects can be noticed in the early days of each season. This is natural since most people do not start their equipment (i.e., space heaters and air conditioners) from the first day weather conditions start to change. In Fall and Spring, it was found that the early days of these seasons were still under the effect of the previous season; inertia effect. For days in the middle and later part, it was found that meteorological conditions do not have that strong effect on the system load as in other seasons. In other words, changes in system demand in the middle or later part of Spring and Fall are effected by other factors, such as inertia and natural differences between different days of the week, more than effects of changes in weather conditions. However, this does not mean that the effect of changes of weather were excluded in this study, but rather given less weight than other seasons.

The second step of the off-line calculation process was to define accurately the functional relationships between the variables that have been found to have a strong relationship with electric demand in the first step. The Multiple-Regression technique in the MINITAB statistical package was used to define these relationships. The size of data used in the test for each variable was a full season (3 months) except for humidity, where the relationship has been studied using one week of data. For Spring, Summer and Winter this has been repeated for every week. Since the kind of relationships that exists between each variable and the electric load was unknown it was essential to apply the multiple regression technique on all possible functions of each variable. For each variable, three predictors were created - simple linear, polynomial and exponential functions of each variable. The multiple regression technique has the ability to drop any predictor with a very small correlation factor. After dropping the weak predictors, another test was made to see whether the predictions will improve or not if the function has a constant or not. After repeating this process for every one of the five factors above and for the four seasons the following results were obtained.

1. Wind Speed: in winter, there is a linear relationship between changes in wind speed and changes in electric demand for ambient temperature below 30°F. Also, it was found that the effect of wind speed does not increase when the temperature drops below 10°F, i.e., it will reach saturation. Thus the mathematical formulation for this is:

$$F(ws) = 0\,, \quad temp > 30°F$$

$$F(ws) = ws \times (30 - temp)/5.0\,, \quad 10°F < temp < 30°F \tag{2}$$

$$F(ws)_{max} = 4.0 \times ws\,, \quad temp < 10°F \tag{3}$$

where

F(ws) = function of wind speed to be included in defining the effective temperature, °F.
ws = wind speed in miles per hour

temp = ambient dry-bulb temperature in °F.

2. Humidity: The effect of humidity will be considered for late Spring, Summer, and early Fall. THI values will replace the values of dry-bulb temperature for all equations and rules in the following conditions:

   A. The date of the forecasted day falls between April 1st and September 30th.

   B. The dry-bulb temperature is higher then 76°F and lower than 91°F.

3. Temperature: The changes in load were found to have strong relationships with all predictors; the linear, polynomial, and exponential functions of the changes in temperature. However, it was very clear that a single equation or a set of equations will not be able to produce accurate predictions of changes in the system load as a function of changes in temperature. Several reasons were found for this. First, changes in temperature have different effects on changes in system load from one hour to another during the same day. Second, equal changes in temperature with different references (i.e., 50-60°F and 60-70°F) have different effects on people too. For this reason it was important to take two steps to solve the problem.

   A. Divide the day into five periods according to the hour of the day: 0-5, 6-9, 10-13, 14-19 and 20-23; and

   B. Select different bands for reference temperature with a bandwidth of 5°F for each. For winter, the first band is under 20°F and the last above 70°F. For summer, the first group was under 50°F and the last above 95°F.

For the first case, it was found that the relative effect of changes in temperature between the periods of the day is constant for all seasons. A weighting factor (WF1) was extracted from the regression analysis for each period of the day. The following values of WF1 describe the relative effect of change in temperature for the five periods in sequence

10 : 35 : 25 : 30 : 20

These values of WF1 will be normalized when used to produce the forecast by dividing each value by 30.

For the second step, the Multiple Regression technique was used to study the relationship between changes in ambient temperature for each temperature band and changes in system load. This study has revealed the following results.

1. Changes in temperature may cause different changes in system load depending on the reference temperature band. The severity of the temperature band is reflected in the effect of changes in temperature. For example, for an increase of ambient temperature of 10°F from a reference of 50°F has much less effect on load than a change of 10°F from a reference of 80°F in Summer. For this purpose, a weighting factor WF2 was extracted for each temperature band for both summer and winter. Table 1 compares the values of WF2 for each band in Summer and Winter.

2. Values of WF2 are mostly stable during Summer and Winter, while in Spring and Fall those values of WF2 are changing rapidly. To find the best value of WF2 for every day in these two seasons, the following linear equation was used

$$WF2_{SF} = WF2_{SUM}, \quad temp > 55°F$$

$$WF2_{SF} = WF2_{WIN}, \quad temp < 35°F$$

$$WF2_{SF} = \frac{(55 - temp)xWF2_{SUM} + (temp - 35)xWF2_{WIN}}{20}, \quad 35°F \leq temp \leq 55°F \qquad (4)$$

where

$WF2_{SF}$ = weighting factor WF2 for Spring or Fall

Table 1. Values of weighting factor WF2 for Summer & Winter

Temp.(°F)	<50	50-55	56-60	61-65	66-70	71-75	76-80	81-85	86-90	91-95	>95
WF2	.2	.3	.5	.8	1.1	1.4	1.8	2.5	2.7	2.9	3.0

SUMMER

Temp.(°F)	<20	20-25	26-30	31-35	36-40	41-45	46-50	51-55	56-60	61-65	>65
WF2	3.0	2.8	2.6	2.5	2.2	1.8	1.4	1.0	.5	.3	.1

WINTER

$WF2_{SUM}$ = weighting factor WF2 for Summer

$WF2_{WIN}$ = weighting factor WF2 for Winter

temp = ambient dry-bulb temperature in °F.

Even though this has been found to be the best mathematical approximation of WF2 for Spring and Fall, it was found that it cannot work very well for all days of the season. The reason for that is the wide variation in weather conditions in the same week or month of the season. For this purpose, a revising mechanism was developed to find the best approximation of WF2 value. This mechanism uses an iteration process similar to the one used to find the root of a function using the method of Interval Halving. This revising mechanism is discussed in detail later in this chapter.

3. After considering the weighting factor WF1 and WF2, it was found that for changes in temperature of less than 10°F there is a constant rate of change in the system load. This rate was found to be almost stable at 25 MW/°F for Virginia Power. It is important to note that this rate will be different for other utilities because of differences in types of loads, general system load shape and size.

4. For changes of 10°F and above, changes in demand were found to be proportional to the square of changes in temperature after considering the weighting factors, or

$$\Delta MW \propto \frac{\Delta t^2}{4.0}, \quad \Delta t \geq 10°F \tag{5}$$

where

ΔMW = changes in system load in MW

Δt = changes in temperature (or THI) in °F.

However, the value of ($\Delta t^2/4.0$) will be clamped at 60 for saturation reasons.

4.1.4 On-Line Calculations

The on-line calculations include the execution of a set of rules controlling the process of generating the load forecast. A summary of major rules developed for the forecast algorithm is presented in the following. Each rule listed here is really a set of rules, clustered around similar derivations.

Rule 1. The reference day. For weekdays between Tuesday and Friday the reference day is the previous day provided that it is not a holiday. If the previous day is a holiday then the closest working day is considered. For Monday the reference day is Friday. For Saturday and Sunday it is the previous Saturday or Sunday. For, holidays the last Saturday is chosen as the reference day.

Rule 2. Reshaping the reference load curve. The reference load shape for the target day is reshaped according to the expected load variation between days and weather inertia effect.

Rule 2a. Reshape the reference load curve to take into account the variations in load from one day to the other. Two factors were extracted using the "MINITAB" statistical package [22] to lower or raise certain portions of the load curve for some days of the week. For the system studied, it was observed that a Tuesday curve is usually lower than a similar Monday curve between 0600 and 1000 hours. Thus when used for a Tuesday the reference Monday curve is lowered by 5% between these hours. For similar reasons the reference Thursday night curve is raised by 8% when used as a reference for Friday between 2000 and 2300 hours.

Rule 2b. Load inertia effect. The load during the early hours of the day, following a hot or cold day, continues to show the effects of the previous day. This effect usually wears off in a linear fashion as the day progresses. It was observed that the following linear equation best represents the correction that is necessary to take this inertia effect into account

$$\Delta MW_h^{in} = (MW_{00}^T - MW_{00}^R) \times (24 - h)/24 \quad (6)$$

$$MW_h^{F1} = MW_h^{Rm} + \Delta MW_h^{in} \quad (7)$$

where,

ΔMW_h^{in} = megawatt correction due to inertia at hour h

MW_{00}^T = load at hour 00 of the target day

MW_{00}^R = load at hour 00 of the reference day

h = hour of the day for which correction is sought

MW_h^{F1} = 1st level forecast of load for hour h

MW_h^{Rm} = Reference day's load for hour h modified according to rule 2a.

It should be noted here that the 24-hour forecast is really 24 separate forecasts ranging from one to 24 hour in lead time. The load forecast for hour h on the target day is linked to the load and the weather conditions at hour h of the reference day.

Rule 3. Adjustment of MW_h^{F1} due to dissimilar weather conditions between the reference and target days. Before applying the rules, certain grouping and preprocessing are carried out. For example, the day is divided into five periods. These are hours 0-5, 6-9, 10-13, 14-19 and 20-23. Observed temperatures are divided into two sets, one for summer and the other for winter, with several groups in each set as it was shown in Table 1. Historical load and weather data are analyzed to relate the change in load and the change in temperature. This is found to be different for different seasons. A reference value of 25 MW/°F is used as a compromise.

A complex set of rules is applied to the hourly load (MW), temperature and wind data in order to come up with a forecast.

Rule 3a. This gives the basic relationship between changes in temperature (Δt) and load (ΔMW). It is observed that :-

1. In winter $\Delta MW > 0$ if $\Delta t < 0$

2. In winter when ambient temperature is below 30°F the wind chill effect should be considered

$$\Delta t_e = \Delta t - F(ws) \tag{8}$$

Δt_e is clamped at 10°F due to saturation effect.

where,

Δt_e = effective Δt

F(ws) = function of wind speed defined in equations 2 and 3.

Rule 3b. The influence of Δt in effecting ΔMW is different at different hours of the day. A weighting factor "WF1" has been developed by examining a large number of such relationships using MINITAB. As it is shown earlier, the value of WF1 ranges between .333 and 1.0.

Rule 3c. The influence of Δt in effecting ΔMW is also different at different ambient temperatures. The weighting factor "WF2" which has been explained earlier has been developed by examining a number of such relationships. It is found that WF2 ranges between 0.1 and 3.0.

Rules 3a, 3b and 3c are merged to obtain the following equation

$$\Delta MW_h = \pm \Delta t \times WF1 \times WF2 \times 25, \quad \Delta t \leq 10°F \tag{9}$$

$$\Delta MW_h = \pm\frac{\Delta t^2}{4} \times WF1 \times WF2\,,\ \Delta t > 10°F \qquad (10)$$

where,

+ in summer

— in winter

Δt will be replaced by Δt_e if necessary.

The final forecast is obtained by two corrections obtained from equations (7), (9) and (10). Therefore the final forecasted load at hour h is:

$$MW_h^{FF} = MW_h^{F1} + \Delta MW_h \qquad (11)$$

It should be reiterated here that WF2 is automatically revised if the average error for the peak hour over three consecutive days exceeds 3%.

Figure 11 through figure 13 illustrate the process of generating the forecasted load curve for a certain day in winter.

4.1.5 Self-Revising Mechanism

As it was shown earlier, the lack of regularity in changes in weather conditions makes it difficult to create fixed rules or constant factors. Such conditions are very clear in some seasons with transient weather conditions, or in a season with abnormal conditions. For this reason the author has developed a self-revising mechanism to take some corrective actions when the accuracy of the generated forecast is beyond a predefined limit. The major role of this mechanism is the generation of the best possible value of the weighting factor WF2. The second role is to modify the value of 25 MW/°F used in equation (9).

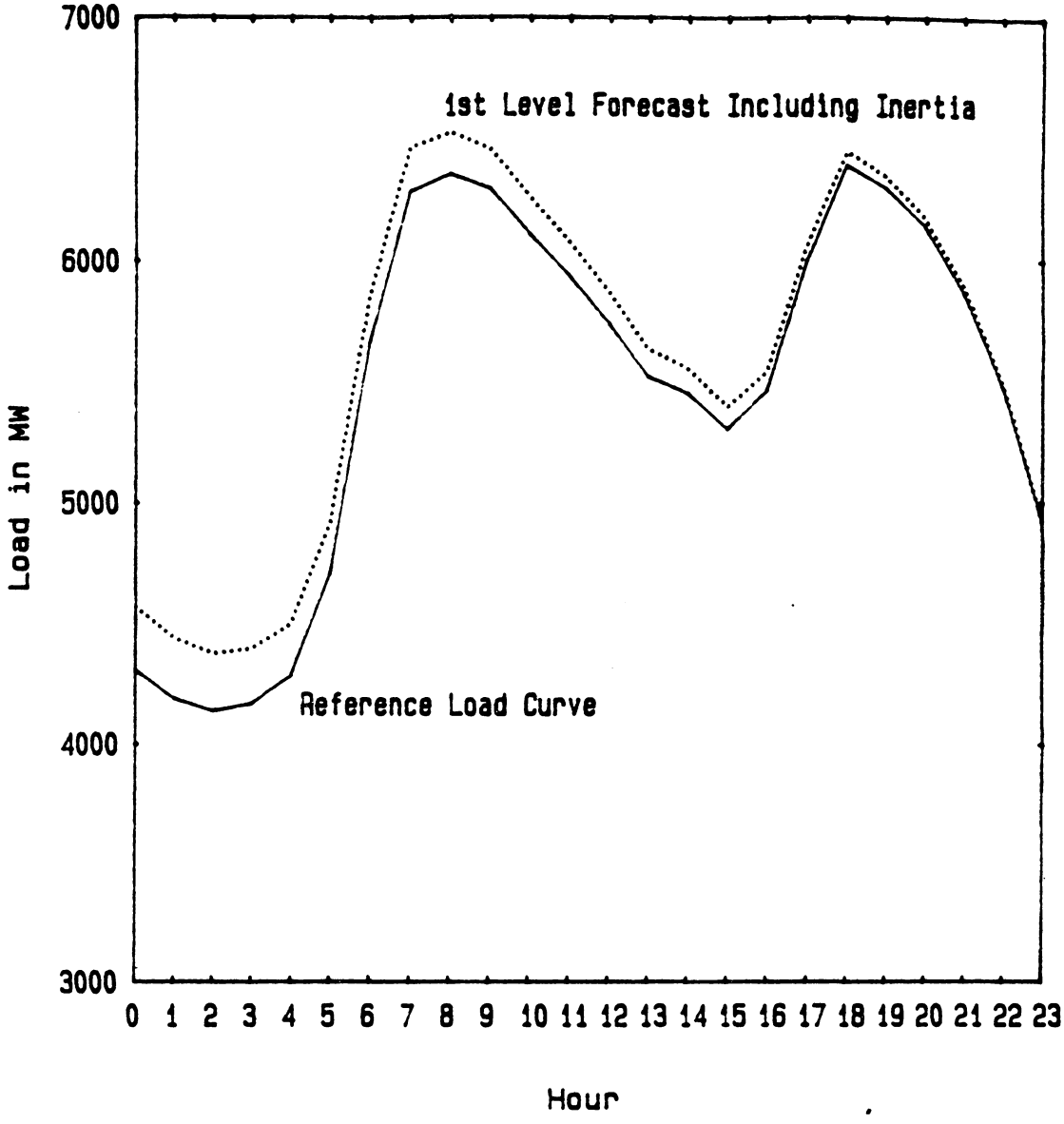


Figure 11. Select the reference day and modify it to include effect of inertia

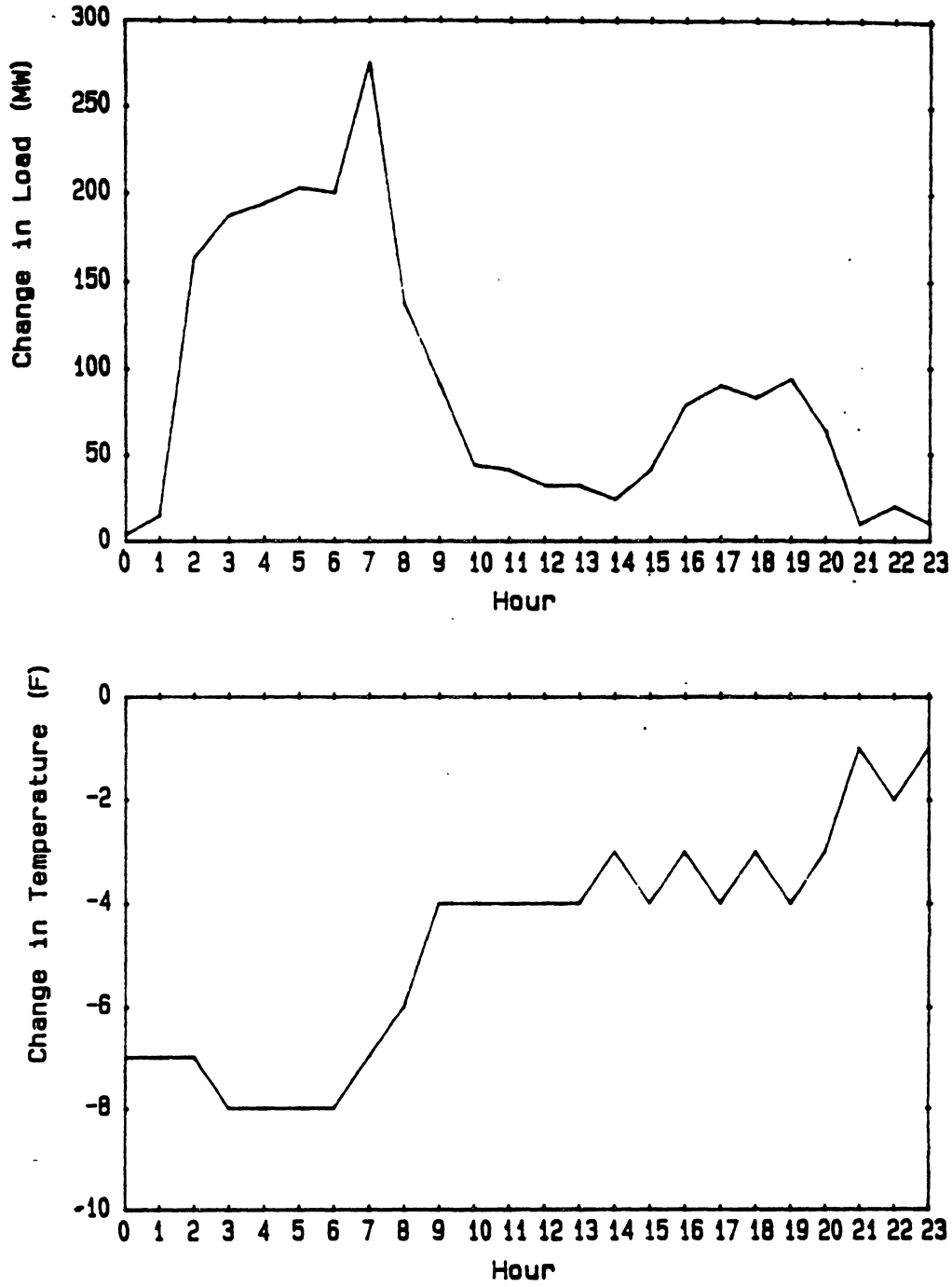


Figure 12. Changes in load due to changes in effective temperatures (winter)

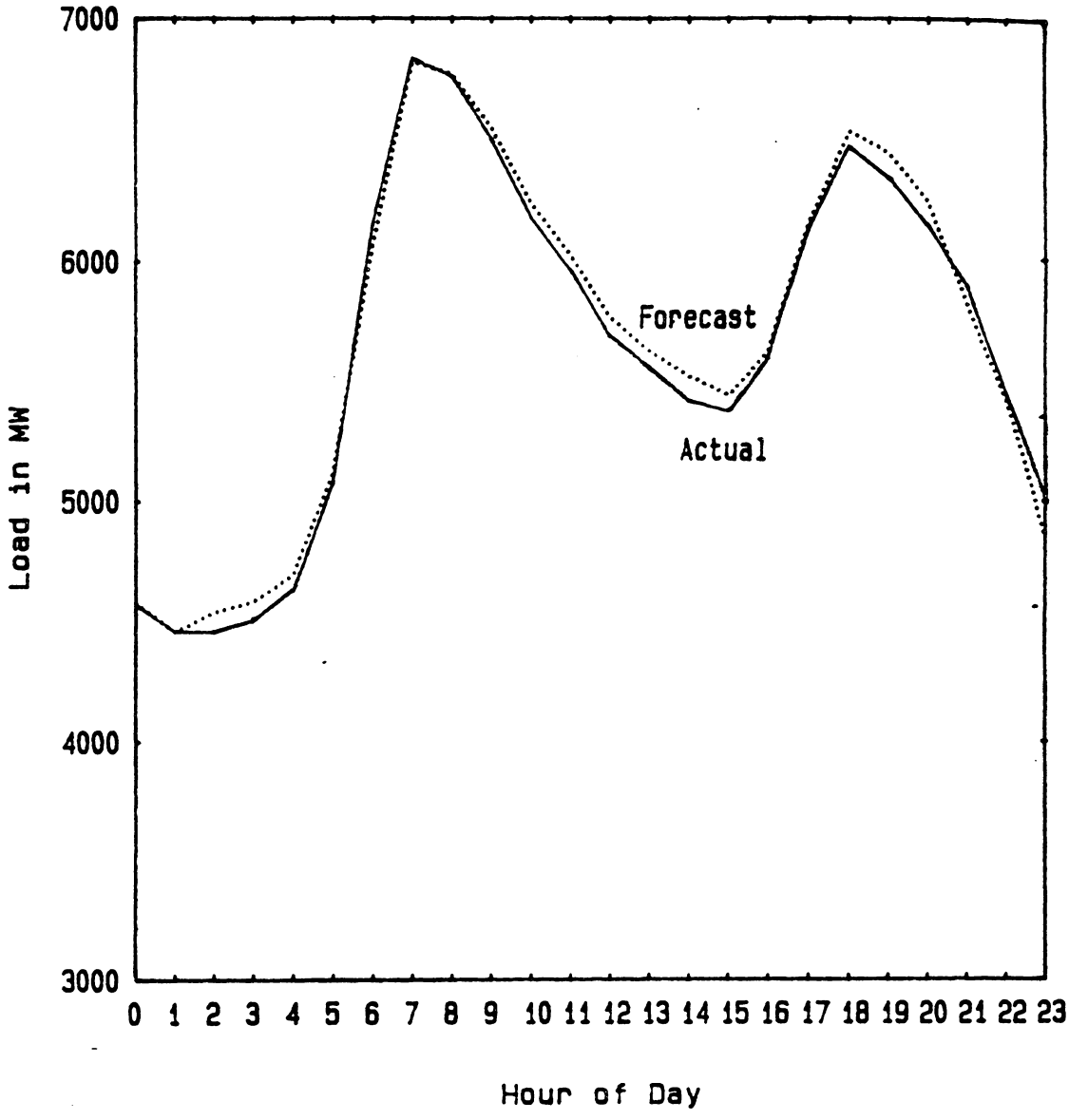


Figure 13. Generation of final forecast by adding the effect of weather

After creating the approximate value of $WF2_{SF}$ using equation (4), the algorithm will use the method of Interval Halving to generate a new value. This value will be tested on the last two days. If this generates better forecasts then it will proceed with the iteration process. Otherwise it will switch to the other side of the value. This process is explained in the flowchart shown in figure 14.

One of the major decisions made during the process of developing this mechanism was the determination of the error threshold value beyond which the rule-revising algorithm will be initiated. The final decision on this problem was delayed until the whole process was completed. After that, five different values; 2%, 2.5% 3%, 3.5% and 4%, were tested for the data of 1986. The statistical analysis has shown that a threshold value of 3% can generate the best forecast. The explanation for this result can be as follows: for small values of the threshold the revising mechanism will be initiated very often even at times when no correction action is required and the error values cannot be improved by any means. In this case the revising mechanism may generate new values which may increase the error values for the coming days. However, for higher values of threshold (3.5% and 4%) the initiation of the revising mechanism will be delayed until the generated forecasts get very bad in some cases.

4.2 Results & Discussions

Results obtained by applying the rule-based load forecasting algorithm are summarized in this section. This algorithm has been tested on the hourly load data for Virginia Power for 1983 and 1986. The hourly ambient temperature and wind speed (for winter season only) for Richmond, Norfolk and Washington, D.C. for those same years are used for this purpose. The MINITAB package [22] is used on the 1986 data for generating the load reshaping, WF1 and WF2 factors. The same set of factors are used for 1983 and these are readjusted as necessary by the forecast program.

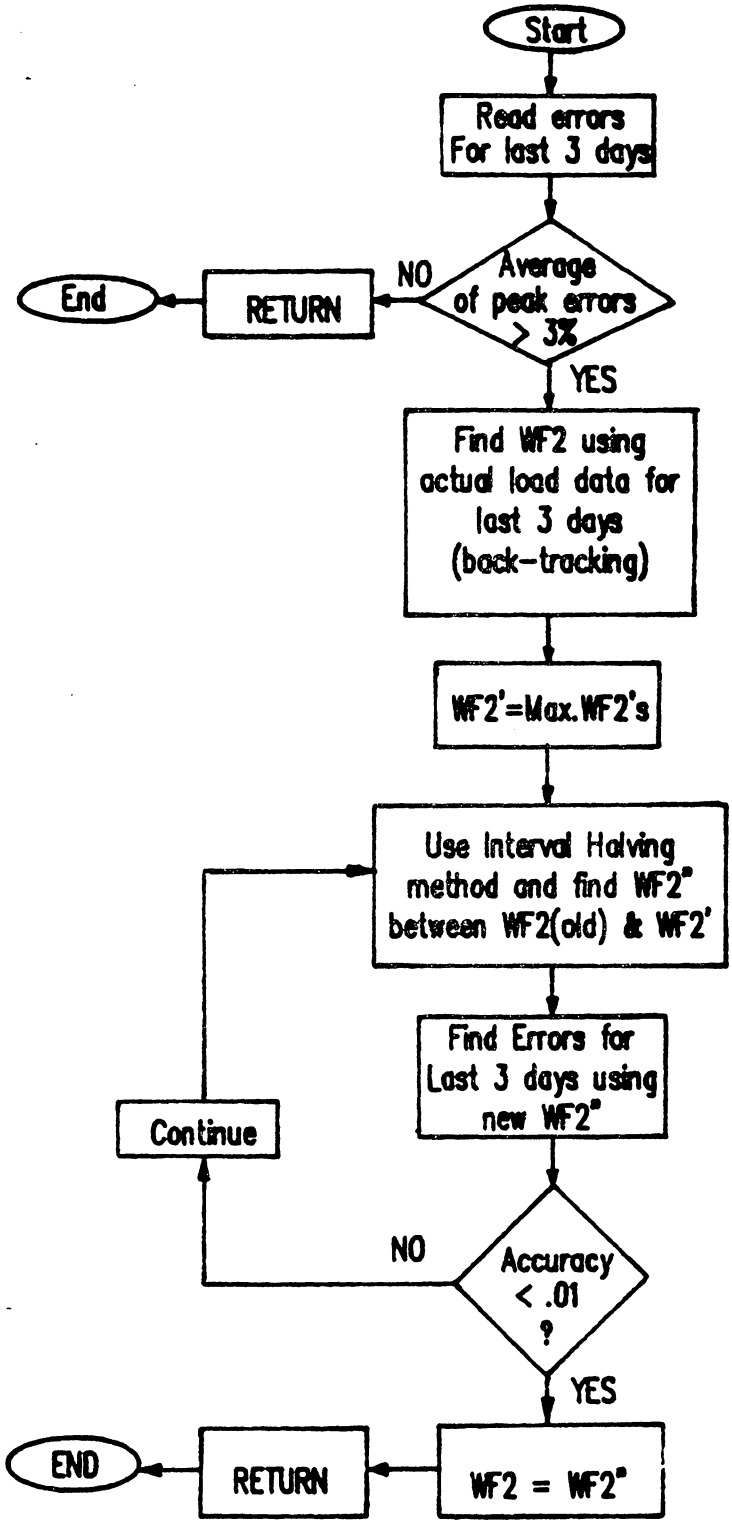


Figure 14. Flowchart of the self-revising mechanism

Comprehensive error analyses for 1983 and 1986 are presented in Tables 2 and 3 respectively. These results are based on 24 hourly load and weather observations for 626 days in those two years. Several days are missed due to bad and missing data. The year is divided into four seasons and the absolute average error for every hour for all days of the season is shown in these tables. The error is represented as a percentage of the peak load for the day. The standard deviation is also shown. The average error for 1983 ranged between 0.123% and 2.090% while the same parameter for 1986 ranged between 0.162% and 2.097%. The average monthly errors in Fall and Spring are higher than those of Summer and Winter because of two reasons. First, the daily peak load values in Fall and Spring are much lower than in Summer and Winter, and hence, the same error value (in MW) will create higher percentage error for seasons with lower load. Second, the revising mechanism is initiated only after three days of high error percentages, and hence some bad days will pass before correction actions are taken.

When a 24-hour load forecast is used for direct load control it is important to forecast the peak load of the day as well as the hour of that peak. Of the 626 days for which forecasts were issued, only on seven days the algorithm failed to predict the hour of the peak load when the difference between the two adjacent values at peak time is greater than 50 MW. In other words in 98.96% cases, over a two-year period, the rule-based forecast algorithm accurately predicted the hour of the peak. Moreover, none of these seven days missed happen to be the peak day of the month. Also, it has been observed that in most cases the peak was missed by only one hour.

Table 4 shows that the confidence of having a load forecast with an error less that 4% is more than 90%. This confidence is higher than 97% when the load forecast error is equal or less than 5%.

Table 2. 24-hour Load Forecast Error (%) Statistics for 1983

Hour	Winter		Spring		Summer		Fall	
	Aver.	St.Dev.	Aver.	St.Dev.	Aver.	St.Dev.	Aver.	St.Dev.
0	0.123	0.199	0.186	0.148	0.166	0.179	0.170	0.106
1	0.135	0.125	0.247	0.181	0.243	0.197	0.235	0.209
2	0.593	0.463	0.670	0.438	0.228	0.476	0.935	0.563
3	0.782	0.516	0.879	0.746	0.855	0.605	1.224	0.637
4	0.746	0.660	1.175	0.988	0.899	0.749	1.308	0.777
5	0.952	1.472	1.506	1.238	1.167	0.914	1.786	0.914
6	1.171	1.819	1.485	1.140	1.260	1.791	1.632	1.185
7	1.180	0.769	1.434	1.146	1.291	1.654	1.517	1.118
8	1.170	0.664	1.411	1.257	1.366	1.075	1.580	1.147
9	1.223	1.173	1.377	1.440	1.698	1.238	1.696	1.243
10	1.448	1.112	1.445	1.202	1.668	1.732	1.571	1.254
11	1.453	1.436	1.490	1.080	1.645	1.555	1.659	1.250
12	1.606	1.475	1.803	1.421	1.857	1.881	1.674	1.416
13	1.670	1.503	1.974	1.361	1.984	1.767	1.941	1.699
14	1.727	1.419	1.905	1.161	1.877	1.395	2.086	1.777
15	1.634	1.214	2.090	1.063	1.957	1.753	1.848	1.601
16	1.851	1.200	2.031	1.038	2.043	1.487	1.599	1.518
17	1.934	1.818	1.998	1.033	1.985	1.630	1.995	1.751
18	1.099	1.671	1.752	1.728	1.786	1.729	1.574	1.683
19	1.027	1.631	1.514	1.732	1.822	1.744	1.764	1.710
20	1.947	1.651	1.594	1.651	1.713	1.754	1.647	1.676
21	1.981	1.547	1.770	1.765	1.822	1.717	1.895	1.619
22	1.722	1.623	1.634	1.627	1.605	1.646	1.769	1.574
23	1.864	1.946	1.900	1.765	1.868	1.356	1.717	1.976

Table 3. 24-hour Load Forecast Error (%) Statistics for 1986

Hour	Winter		Spring		Summer		Fall	
	Aver.	St.Dev.	Aver.	St.Dev.	Aver.	St.Dev.	Aver.	St.Dev.
0	0.162	0.114	0.243	0.151	0.250	0.208	0.171	0.127
1	0.118	0.117	0.261	0.186	0.278	0.237	0.183	0.136
2	0.572	0.401	0.552	0.298	0.451	0.374	0.653	0.472
3	0.485	0.463	0.666	0.453	0.597	0.417	0.601	0.442
4	0.479	0.405	0.708	0.545	0.752	0.521	0.740	0.544
5	1.119	0.566	0.936	0.979	0.755	0.619	0.874	0.672
6	1.110	0.584	1.378	0.943	1.133	0.571	1.207	0.716
7	1.323	0.578	1.696	0.867	1.287	0.633	1.327	1.209
8	1.296	0.541	1.719	0.880	1.277	0.568	1.416	1.127
9	1.254	0.580	1.549	0.914	1.262	0.603	1.536	1.653
10	1.140	0.651	1.837	1.112	1.328	0.664	1.611	1.688
11	1.066	0.575	1.778	1.105	1.429	0.582	1.713	1.666
12	1.036	0.624	1.636	1.279	1.399	0.666	1.701	1.616
13	1.242	0.786	1.746	1.281	1.919	0.779	1.953	1.871
14	1.265	0.801	1.837	1.234	1.983	0.749	1.970	1.892
15	1.276	0.854	2.097	1.371	1.855	0.871	1.909	1.820
16	1.372	0.780	1.970	1.332	1.965	1.041	1.951	1.897
17	1.314	0.782	1.987	1.289	1.914	1.042	1.877	1.826
18	1.217	0.738	1.837	1.243	1.778	1.028	1.604	1.160
19	1.108	0.710	1.513	1.118	1.754	0.928	1.545	1.184
20	1.130	0.736	1.573	1.025	1.693	0.971	1.801	1.204
21	1.152	0.822	1.664	0.972	1.732	0.928	1.837	1.331
22	1.116	0.865	1.732	0.987	1.774	0.860	1.647	1.360
23	1.378	1.073	1.655	0.927	1.467	0.792	1.502	1.143

Table 4. Confidence intervals for 24-hour load forecast in (%) for 1986

Hour	<1%	<2%	<3%	<4%	<5%	≥5%
0	87.8	97.3	100	100	100	0
1	72.0	96.8	99.4	100	100	0
2	75.1	94.5	99.1	99.7	100	0
3	42.3	91.0	96.3	99.3	100	0
4	36.0	83.6	92.1	95.6	99.7	0.3
5	37.0	82.4	91.3	93.4	98.7	1.3
6	30.2	81.8	92.2	94.1	99.1	0.9
7	28.6	78.7	91.5	93.9	99.0	1.0
8	27.5	77.4	87.8	93.3	98.5	1.5
9	30.2	76.4	85.9	91.7	98.3	1.7
10	31.7	71.2	87.5	93.2	99.1	0.9
11	26.5	72.2	88.6	93.9	98.8	1.2
12	29.6	70.2	87.9	94.1	99.3	0.7
13	22.2	71.4	81.2	93.9	98.6	1.4
14	20.6	67.2	85.8	92.5	98.9	1.1
15	22.2	67.2	84.7	91.5	97.9	2.1
16	22.2	67.7	85.8	91.7	98.7	1.3
17	22.2	68.8	86.4	92.6	99.0	1.0
18	29.1	75.2	83.7	91.7	99.1	0.9
19	31.2	80.5	87.4	94.1	98.9	1.1
20	29.1	77.3	83.3	93.2	99.1	0.9
21	28.0	75.7	81.8	91.9	98.7	1.3
22	24.9	78.4	83.1	92.3	98.9	1.1
23	24.5	77.9	82.5	90.5	99.5	0.5

Figure 15 presents detailed information about the absolute value of the forecast error (%) at the peak hour for workdays in 1986. The instances when the built-in rule-revising technique became active in response to a (three-day average) forecast error of 3% or above are also shown in this figure. It is a proof that the automatic rule-revising technique responds to the changing load and weather patterns, and it is able to keep the forecast error to a minimum.

Normally the forecast for any day will be based on what happened on the reference day and earlier, and the forecasted weather for that day. Since the results and error analysis presented so far are based on historical data, recorded weather data were used in place of forecasted weather data. It should be understood that when issuing live forecast, the exact information on weather that has been utilized for these tests will not be available. It is interesting to speculate what will happen in that case and what will the effect of errors in weather forecast be on the load forecast. A brief analysis along these lines is provided in the following.

4.3 Factors Affecting Accuracy of Load Forecast

In addition to the natural differences in electric demand from one day to another, there are several factors that can affect the accuracy of the load forecast. Their influence, however, can be reduced by proper implementation of information transfer and bad data detection. The most important factors affecting the accuracy are

1. Bad data in the database
2. Inaccuracy of on-line load data measurements
3. Unplanned sale/purchase of power between utilities
4. Weather forecast errors

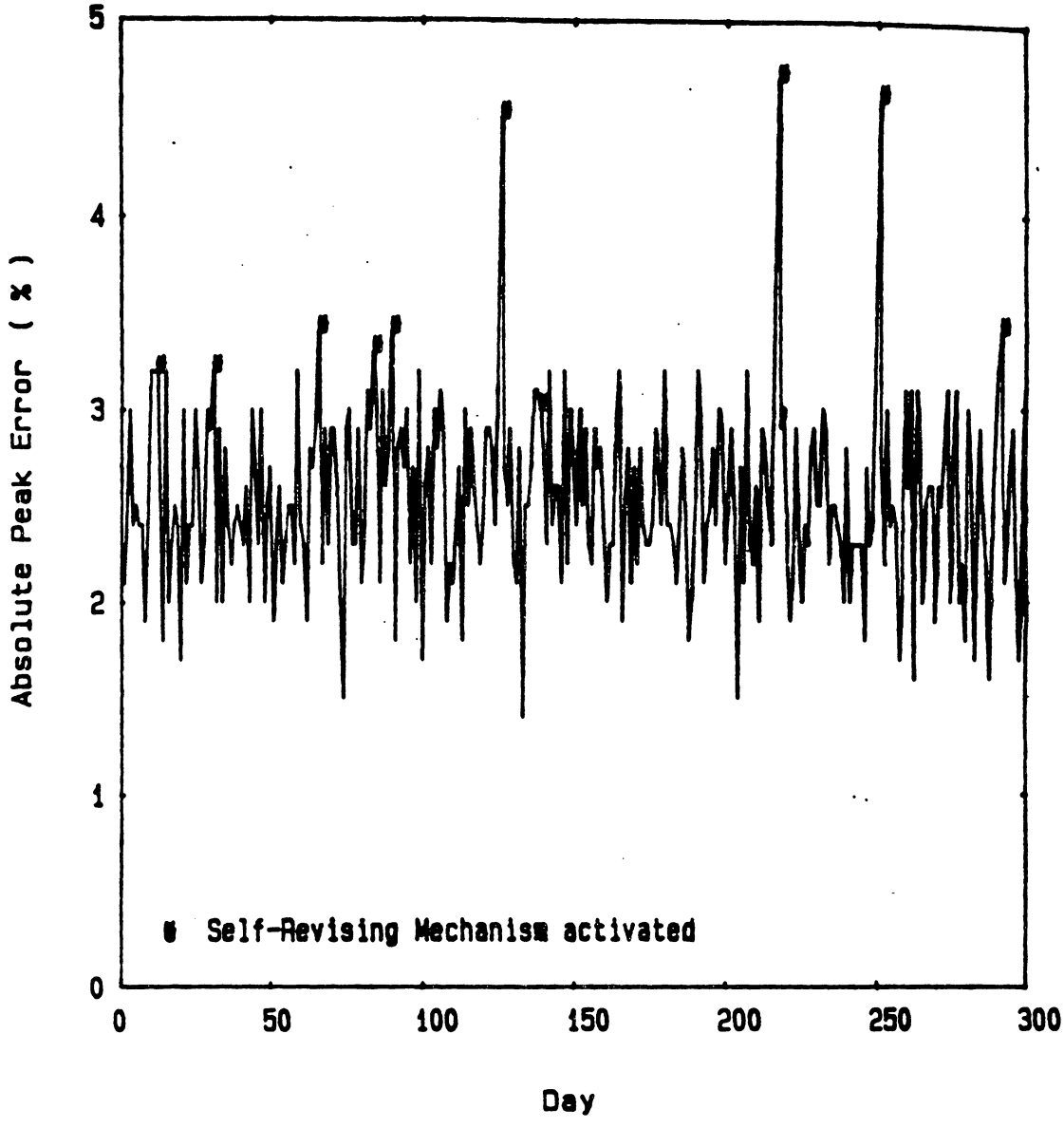


Figure 15. Error Pattern for Daily Peak Load

5. Direct load control impacts.

The following sections will discuss in detail how these factors can affect the accuracy of load forecast and how to avoid each of them.

4.3.1 Effects of Bad Data on Load Forecast

The database consists mainly of historical load and weather data. This database is updated at least once every hour and scrolled (24 lines up) once every day. Even though data collected from the generating plants and weather stations pass through different filters, there is still a chance of bad data to pass through and get archived in the database. This will happen when the error is within the range of filter. Refer to section 3.1.1.1 for discussion on filtering. The main reason for such bad data is the noise from modems or transmission lines. Also, bad data can be generated by read/write errors during the archiving process because of bad sectors on the hard disk or memory fault. When bad data is used in the process of generating the load forecast, a good chance of producing erroneous results exists. Such errors in the forecast may be minor and affect only one hourly forecast or it might be more serious and affect the whole forecast. The severity of these errors depends on the difference between the actual data and the bad data replacing it in the database. Since there is no automatic filtering for archived data, the only solution for this problem will be to correct the database manually. If the occurrence of bad data happens very frequently, then it is important to know the source of noise and fix it or modify the filter to detect it.

4.3.2 Inaccuracy of On-line Load Data Measurements

The on-line computation of the instantaneous system load is done by measuring the total generation of the system. This method provides only an approximate value of the system load.

However, there is a difference between actual system load and generation. For Virginia Power, for example, that difference generally ranges between -60 to 60 MW. Such difference can cause an absolute error that ranges between 0-1.5%.

The difference between actual load and the measured load affects the forecast in another way. As it was shown earlier, collected load data will be archived in the database for future usage. This data will be used as the reference for the generation of a new forecast. If the difference between the actual load and the archived value was positive for example, and that for the new day was negative, then the probability of having a higher error will increase.

4.3.3 Effect of Sales to Other Utilities

All load forecast algorithms consider changes of demand as a natural response to changes in weather and/or customer behavior. If the electric utility decided to sell power to another company, then an increase in the system load will occur. Such increase will not be forecasted by the load forecast program. The only way to produce an accurate load forecast that encounters such changes in demand is to have better communication between the control center and the load management system. The transfer of information about electric sales can be done manually or automatically through computer-to-computer communication. The actual value of load forecast will be:

Actual Forecast (MW) = Generated Forecast (MW) + Sales (MW) - Purchases (MW).

4.3.4 Effect of Weather Forecast Errors

The effect of weather forecast errors on load forecast is shown in figure 16. This is related to the discrepancies seen between the forecast and observed temperatures as illustrated in figure 17. The observed load shape for a typical winter day and the off-line forecast (using observed weather data) match quite well. The on-line forecast load shape

(using forecast weather data) is a bit off. This is caused by the error in temperature forecast shown in figure 17.

It is noted from figure 17 that upto hour 0900 the discrepancies between forecast and observed temperatures are under 1°F. And there is no difference between the on-line and off-line load forecasts upto this hour. At hour 1400, however, when the temperature forecast error is 3.67°F the difference between the on-line and off-line load forecasts is almost 200 MW.

4.3.5 Effect of DLC on Forecast

A major advantage of the rule-based forecasting algorithm presented here is its ability to incorporate the effect of direct load control (DLC) on the load forecast. When a load forecast is issued and it is expected that a new peak hour load (PHL) will be set for the month, some pre-set DLC action may be triggered. The rule-based forecast presented in this study algorithm is sensitive to this action and is designed to automatically issue a revised load forecast taking into account the amount of DLC and the resulting restrike demand. The process of including the effects of load control on forecast is discussed in the chapter VI.

$$\text{Final Forecast (MW)} = \text{Actual Forecast} - \text{Load } Reduction_{DLC} \text{ (MW)}$$

or

$$\text{Final Forecast (MW)} = \text{Actual Forecast} + \text{Load } Payback_{DLC} \text{ (MW)}$$

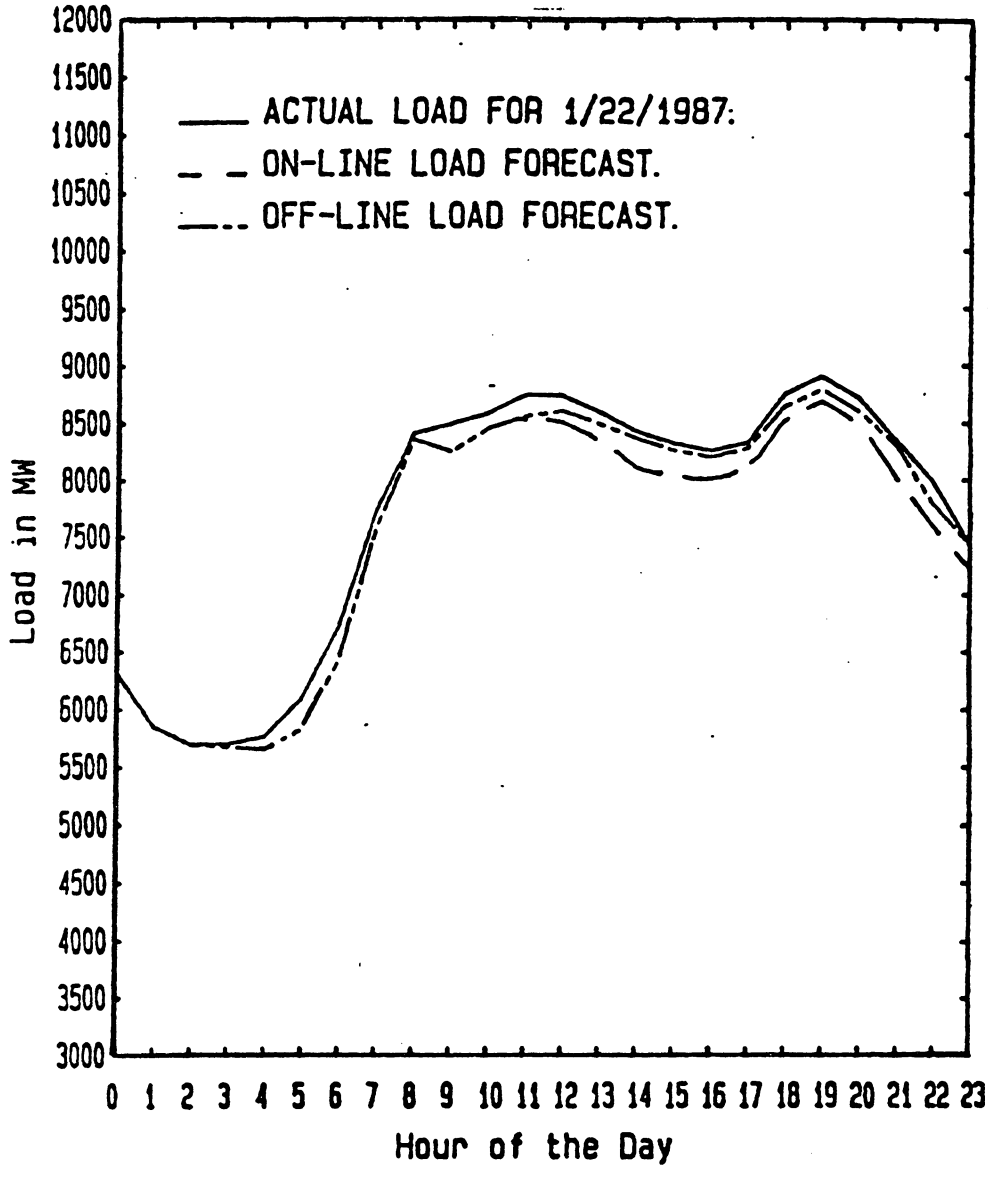


Figure 16. Effect of Weather Forecast Error on Load Forecast Error

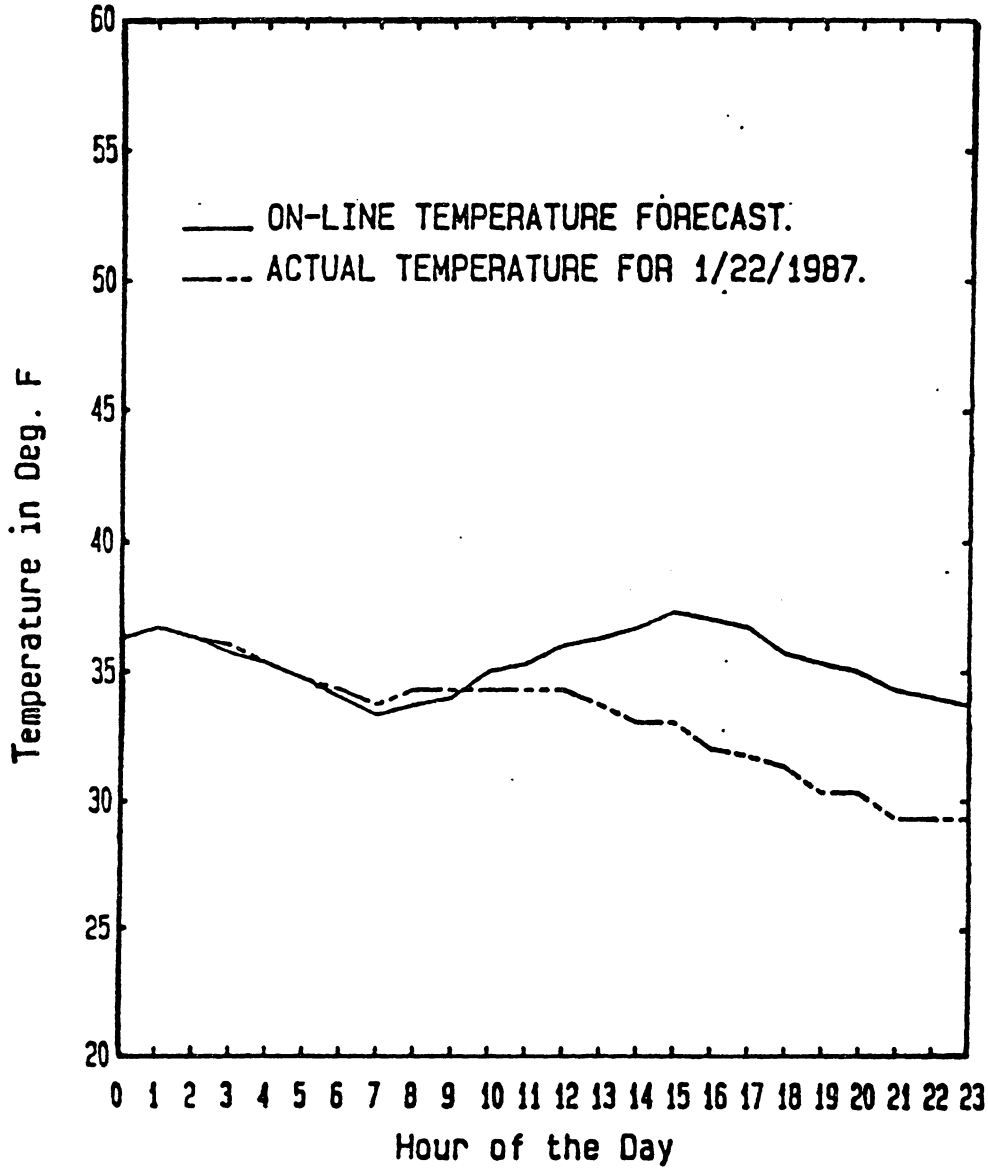


Figure 17. Discrepancies Between Forecast and Observed Temperatures

Chapter V

MODELING OF CONTROLLABLE LOADS

To determine the impact of load management on the system's load shape, it is necessary to determine the electric load characteristics of residential loads (viz., water heaters and air conditioners) - under normal operating conditions. Basically, customer consumption patterns may be altered by three different methods: direct control, indirect control and storage. In the direct control mode, the central controller of the electric utility or the wholesale distributor (e.g., electric cooperative) will send signals to loads turn on or off. In the indirect control mode, the customer reduces his load in response to time-of-use rates. In the storage method, electrical energy is converted to another form (usually thermal energy) and stored for later use.

In this study, direct control will be considered for use with the load management system under design. This method frequently requires the installation of remotely controlled on-off switches to control customer's devices. When the load management system decides to dispatch direct load control, signals (e.g., VHF radio or power line carrier signals) are transmitted to trigger switches that control these devices. These devices can be disconnected for long periods of time, or disconnected and reconnected over short periods in such a

manner that it "cycles" on and off in a desired pattern. When control is done over a large number of devices, the total load of the system will be changed. If the utility could manage this change properly, then the total load imposed on the electric utility can be reduced while serving the same amount of energy.

5.1 Goals of the Development of Load Models

The primary goals of developing load models were to provide the data required by the load control algorithms which decide upon the dispatch of load control. Other applications of load models include available for the evaluation of the overall costs and benefits associated with the implementation of the load management system. In general these goals can be summarized by the following:

1. Determine the normal diversified demand of the customer controllable loads (i.e., water heaters and air conditioners).

2. Determine the load characteristics of these devices under control (reductions and paybacks).

3. Determine the impact of direct load control on the load patterns in terms of demand and energy.

4. Determine the impacts of different control strategies on the load characteristics and the system load.

5. Determine the overall reduction of the system peak loads.

In order to meet these objectives, two interactive models were developed to provide the system with the required data. The first model simulates the normal behavior of water heaters under different weather conditions for different times of the day. The second models the air conditioner load pattern. These models have been developed for this study and are based on available data from tests conducted by several electric utilities in the U.S.A. Further details follow.

5.2 Load Characteristics of Water Heaters

The normal load patterns of water heaters can be determined by averaging the load information of these devices on days without direct load control. This averaging can be done for each hour of the 24 hours of the day and for months with similar or close weather conditions. Also, load curves were modeled for weekends (and holidays) and for weekdays for each month (or set of months with similar conditions).

Available test results have shown that load characteristics of water heaters on weekdays are different from those of weekends and holidays. Generally, water heater demands on weekends and holidays are higher than on weekdays. Also, by comparing the demand of water heaters in the same month for two different years (but with similar weather conditions) it was concluded that the monthly demand does not change by time.

Power demand and energy use of each water heater is highly variable and is influenced by a number of factors such as [23]:

- family size
- tank size
- thermostat setting
- water heater insulation

- ambient air temperature
- inlet water temperature.

Since these factors differ from customer to customer, the average of a large number of water heaters over time was considered. If the number of devices used was very large then this will approximate the diversified load shape of water heaters imposed on the electric utility.

However, it is important to recognize two important factors that affect the design of the load models; diversity and losses. The following discussion will illustrate the importance of these two factors.

5.2.1 Diversity

Diversity is a factor that deals with the relationship between the consumption patterns of a whole group of customers and an individual customer in the group. Since each customer has his own consumption pattern with minimum and maximum demands at times different from others, then the average diversified peak of a group of customers is lower than the sum of all peaks of customers in the group.

The main factor that contributes to diversity is the size of the group being considered. The larger the number of customers the greater is the diversity. Several tens of thousands of units can be considered as a good size of the group in order to represent the diversified load pattern of water heaters in the system. However, some studies [24] have indicated that very little change occurs in the diversified demand per individual with groups of more than thirty customers. Also, these studies have shown that behavioral and physical factors affect diversity. The behavioral factors refer to personal habits, work schedules and desired home temperature. Physical factors refer to variations in house sizes, device sized and insulation

level. Behavioral factors are usually very difficult to quantify and are often neglected in device modeling and analysis.

For physical factors, an average house will be considered for the study. An average home with an area of 600 square feet [24] can be modeled and incorporated as a representative for the whole population. For locations other than Virginia different home sizes can be taken to represent that area. Size of heating or cooling elements were used for the study will be discussed later in this chapter.

5.2.2 Losses

Since data on the consumption of electricity are taken on the device side, losses in the transmission and distribution system are unaccounted for. These losses are proportional to the square of the load being served. From this it can be concluded that the reduction in demand due to load control will lead to the reduction in losses. Similarly, the increase in demand due to payback that follows the control period will cause an increase in losses.

If losses are to be considered in modeling of the loads, extensive details about the transmission and distribution system of each area must be considered. Also, the total loss will be a function of the actual level of the system load as well as the change in load. But since the total reduction in the system load will be minor, and the uncertainty in the load shapes is relatively high, it appears logical to approximate these losses by a small percentage of the change in load. For the purposes of this study, it will be assumed that the effect of losses is equivalent to 5% of the square of the change in demand (reduction and payback). This assumption was based on available test results for different utilities in the U.S. [24].

5.3 Functions of the Load Models

Load models to be designed in this study can be used to facilitate the diversification procedure. These models can be used interactively by the operator or can be called as subroutines by other processes running on the load management system. The main functions of these models can be summarized in the following:

- provide the operator and/or other processes on the system with the hourly diversified loads of water heaters and air conditioners;
- provide hourly system load reductions due to different load control strategies;
- provide hourly system load increases due to paybacks following load control; and
- send a hard copy and/or screen print of the required information upon request.

Figure 18 illustrates the schematic diagrams of the load models and the interfaces with the input terminal and other processes in the system.

5.4 On-Line Loads

The total reduction of system load depends on the average demand of customer loads, number of customers participating in the control program, and the probability of success of the control operation. Three parameters have been defined for the purpose of estimating the possible reduction of system load. These parameters are: diversity factors, penetration levels, and availability. These three parameters will be discussed in detail in later sections.

In this study, there will be an emphasis on using radio communication for load control because it is the most commonly used method. According to EPRI surveys [25] on

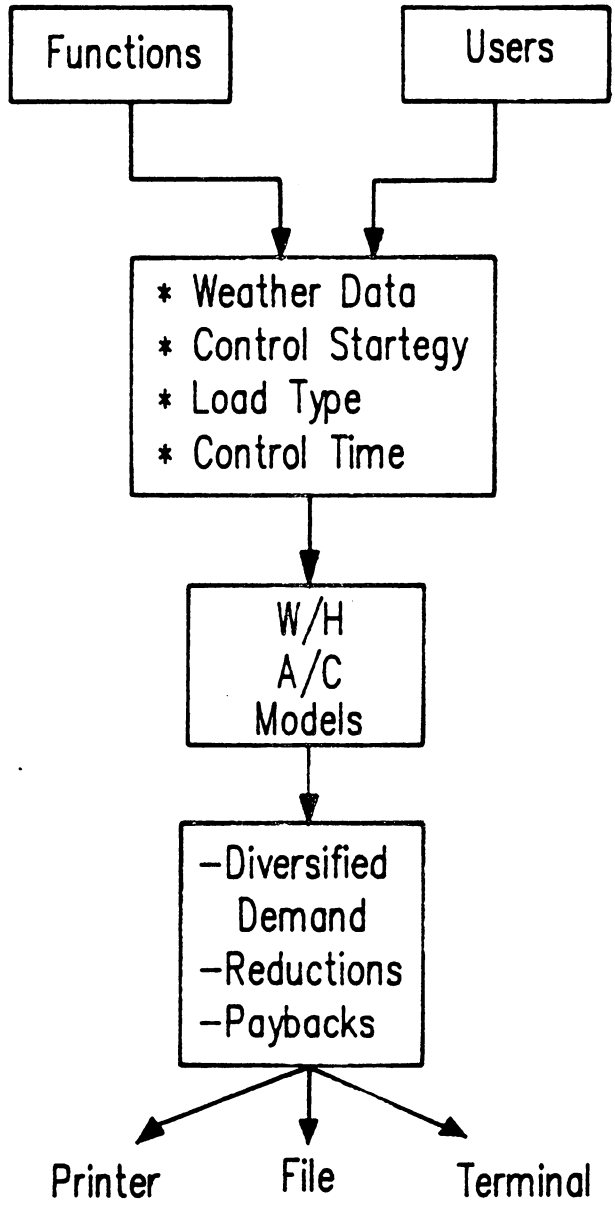


Figure 18. Schematic diagram of load models

demand-side management projects, more than 80% of all direct load control devices in the U.S. are using VHF radio switches. According to this, it is important to investigate the future behavior of these devices which might affect system performance, maintenance requirements and the economy of these systems.

As failures of these switches are randomly distributed in the population, the cost for locating them is high. The decision for deploying remedial maintenance is a function of the availability of the radio switch population. However, there are many factors which influence radio switch availability, most of which are time varying and cumulative. In most studies about load control, a fixed rate of failure was given for these switches. This assumption is not correct since the rate of failure increases with time and it is a function of maintenance.

5.4.1 Diversity Factors

There are a number of common measures of load diversity. A "diversity factor" can be calculated for any part of the power system. It is the ratio of the sum of the individual maximum demands of the various system subdivisions to the maximum demand of the whole system. For example, the diversity factor for a class of appliances can be defined as the ratio of the total connected appliance load to the maximum observed load for that class of appliances at the customer's service utility. The diversity factor is always equal to or greater than one. Diversity arises when the total connected load is not operated all the time, and customer use patterns vary.

The reciprocal of the diversity factor is called "coincidence factor". Another diversity factor is the "contribution factor" which is the ratio of the subdivision demand, at the time of the occurrence of the maximum system demand, to the maximum system demand.

The load model must consider the time varying nature of the customer loads, and none of the previous measures provide information on the shape of load curves. Another measure, the "diversity fraction", refers to the ratio of the instantaneous load of nay subdivision to the

maximum observable load of that subdivision. If we consider two arbitrary load curves, as shown in figure 19, the following equations can be used to calculate the previous measures [1].

$$\text{Diversity Factor} = \frac{P_1 + P_2}{P_T} \tag{15}$$

$$\text{Coincidence Factor} = \frac{P_T}{P_1 + P_2} \tag{16}$$

$$\text{Contribution Factor(L1)} = \frac{P^*}{P_T} \tag{17}$$

$$\text{Diversity Fractions} = \frac{L_1 + L_2}{P_T} \tag{18}$$

where $L_1, L_2, P_1, P_2, P_T,$ *and* P^* as shown in figure 19.

5.4.2 Penetration Level

The total reduction of the system load depends on the number of customers participating in the control program. In most cases, the service utility pays incentives to its customers to encourage them to participate in the load management program. However, this is not the only limitation for the process of recruiting more participants. Other problems include the difficulty in maintaining receivers at isolated areas, and the need for more than one transmitter to cover the whole area.

The penetration level is the ratio of the number of appliances (for example, water heaters) participating in the control program, to the total number of appliances served by the utility. A 20% penetration level of water heaters of Virginia Power for example, means that

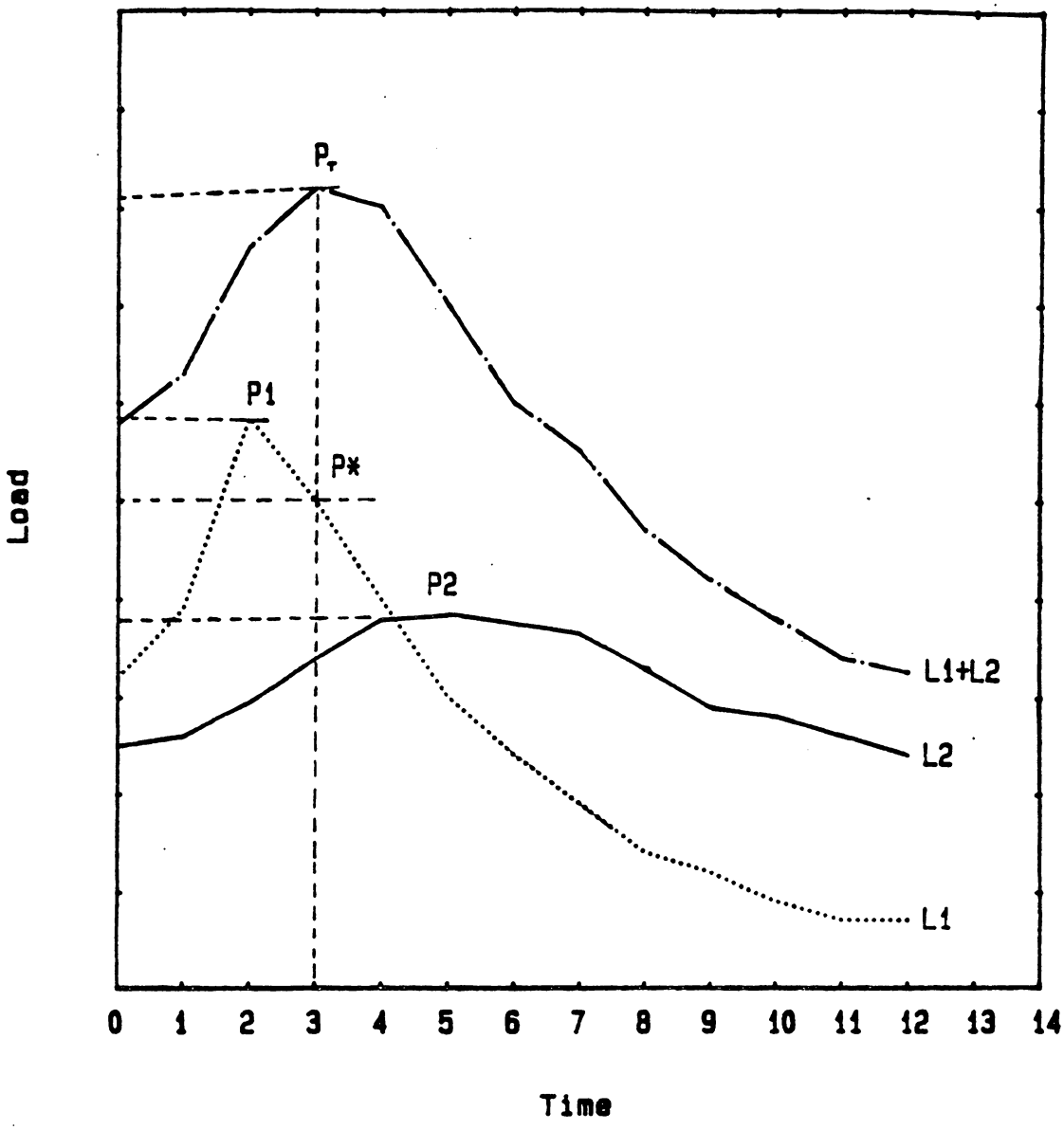


Figure 19. Measures of load diversity

20% of all water heaters of customers buying power from Virginia Power are supplied with control devices.

The penetration level is an important factor in the planning process for the energy management program. It provides planners with the indication of how much additional load reduction they can achieve. Increasing the penetration level will increase the ability to cut more loads, improve the diversity, and reduce the system peak. The improvement of the penetration level can't be done easily. This improvement is usually accompanied with an increase in cost and the possibility of failure. In other words, it is impractical to achieve a 100% penetration level for any type of customer loads.

5.4.3 Availability

Availability can be defined as the measure of radio switch population performance. Availability is reduced by radio switch failures; it is improved by remedial maintenance. The following equation can be used to calculate the availability of switches.

$$\text{Availability} = \frac{\text{Load Reduction}}{\text{Number of Units} * \text{Unit Reduction}}$$

or from the equation

$$\text{Availability} = \frac{\text{UPTIME}}{\text{UPTIME} + \text{DOWNTIME}}$$

So far no comprehensive study has been done to investigate the factors affecting availability and how these factors are distributed over time.

Failures are usually predicted and reported by the following methods.

- Customer Report.

- Routine Inspection.

- Comprehensive Testing.

The cost of detecting a failure is inversely related to the proportion of undetected failed units in the population. In other words, it is probability that an inspector will encounter a failed unit. This can be represented by the following equation [1].

$$\text{Detection Cost} = \frac{\text{Inspection Cost}}{(1 - \text{Availability})}$$

5.5 Switching of Controllable Loads

There are various communication systems and devices utilized by electric utilities for load management and distribution automation functions. These systems and devices range in scope and sophistication from local, time-controlled switches to systemwide remote control of loads, automatic meter reading and the monitoring and control of various distribution system functions.

The earliest systems of load control used time switches to interrupt service to selected loads such as water heaters. This simple device will continue to be used in load management schemes but it is limited by the need to anticipate appropriate fixed time settings. To overcome this limitation, systems have been developed which make possible remote, but not fixed, time shutoff loads by the load management systems. These systems, which are essentially communication systems, allow a utility to remotely activate or deactivate load

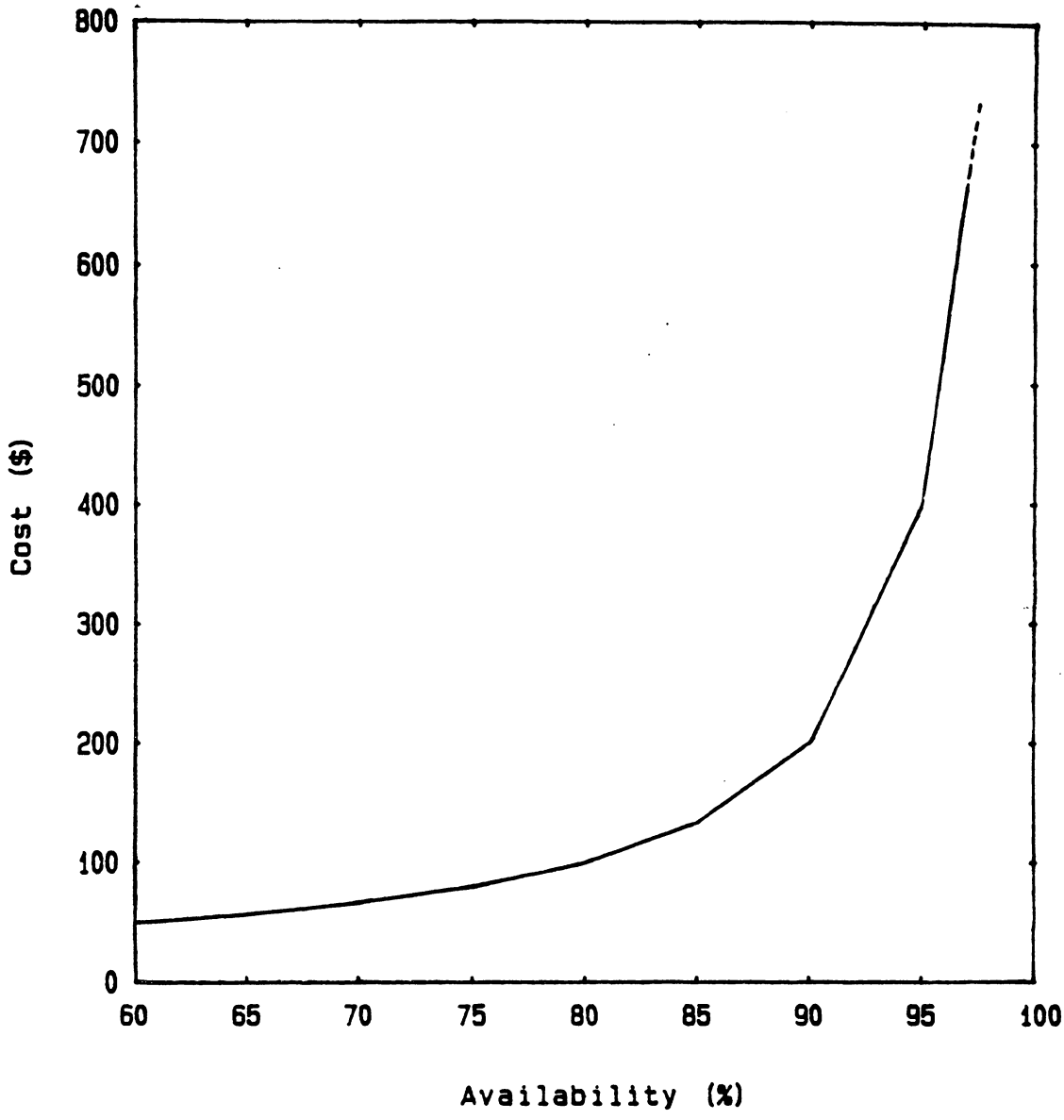


Figure 20. Cost to detect a failure as a function of availability.

control devices located throughout the utility's service area. Although most of these systems are unidirectional, some of them are bi-directional.

The remote switching capabilities of the communication control devices can be used for several applications. The most widespread application of remote switching involves the direct control of the customer load. Other applications include controlling the charging times for thermal storage systems, shifting multi-level meter registers, altering customers of peak conditions and interfacing with local demand limiters and controllers.

Since direct load control will be the main tool for reducing the customer demand by the LMS then the remote switching will be considered. Different means of communication are available to the load management systems. The major three tools for this purpose are: radio, ripple, and power line carrier.

5.5.1 Communication Devices

The unidirectional radio is presently the most widely used type of communication and load control system among U.S. utilities. The key element in a radio control system is the radio switch itself. This device, which is located at the point being controlled, is a combination receiver, tone decoder and relay. The receiver is programmed to respond to only one of the several possible tonal commands being broadcasted by the system's transmitter. Upon receiving the proper command the receiver opens (or closes) its relay. In most cases the relay returns to its original state within a short time (around 7 minutes) unless a follow-up signal is received instructing the unit to continue control. The following figure illustrates the block diagram of the unidirectional radio control system.

A ripple control system utilizes a utilities transmission and/or distribution network as the medium for transmitting signals. Audio frequency impulses are superimposed or "injected" on the normal 60 Hz line voltages by means of a ripple control transmitter. At low audio frequency levels, signals propagate over long distances and through transformers with little

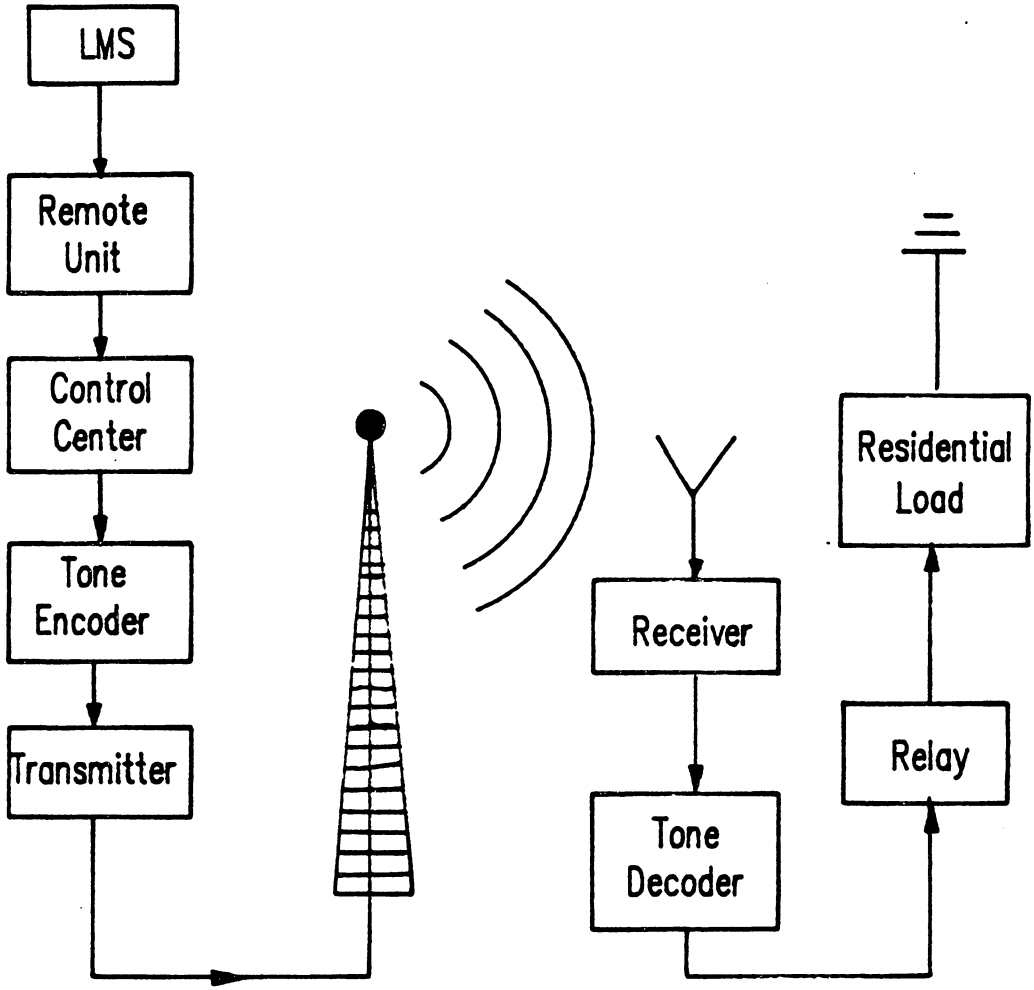


Figure 21. Block diagram of a unidirectional radio control system

attenuation. Conversely, normal line noise is relatively high at these frequencies, which means the injected impulse must be at a high enough power level to maintain an acceptable signal-to-noise level (approximately 0.1-1% of the supply voltage).

The following figure illustrates the block diagram of the unidirectional ripple control system. The impulses generated by the transmitter are injected onto the lines in present patterns of various coded sequences which are in turn received and decoded by ripple control receivers. These receivers perform one or more switching functions at the point of control. Ripple is generally considered as being a unidirectional system.

Power line carrier system operates on essentially the same principle as a ripple control system in that the medium for transmitting power line carrier signals between the point of origin and the point of control is the utility's distribution system.

The system transmits its signals over the power line at high frequency levels in the 5 kHz to 100 kHz range. At frequencies higher than 3 kHz, normal power line noise drops off rapidly, and as such, less signal power will be required to achieve an acceptable signal-to-noise ratio. The functions of the power line carrier system are very similar to the ripple system. Also, the block diagram of both systems are similar.

5.5.2 Categories of Failure

Ten different and independent failure categories have been defined by previous studies [25]. However, some of these categories are not properly failures (i.e., category 9 and 10 in the list). Table 5 contains the list of these ten categories.

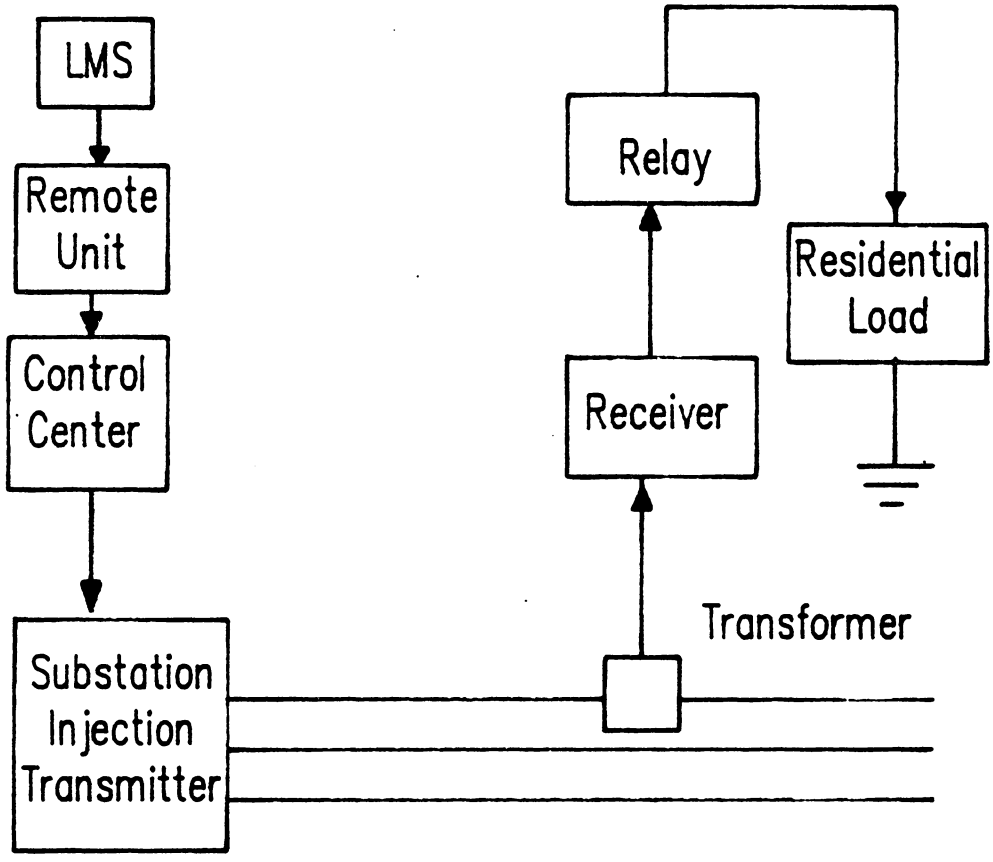


Figure 22. Block diagram of a unidirectional ripple control system

Table 5. Failure Categories

	Failure Category	Hardware Dependent	Time Dependent
1.	Defective installation	No	No
2.	Defective communication path	No	No
3.	Damaged after installation	No	Yes
4.	Unauthorized disconnect	No	Yes
5.	Infant mortality	Yes	Yes
6.	Defective when installed	Yes	No
7.	Common mode failure	Yes	Yes
8.	Random failure	Yes	Yes
9.	Unproductive Installation	No	No
10.	Participant dropout	No	Yes

5.6 Developing the Load Models

During this study no tests were carried out for the purpose of developing the models. The reason for that is the wide availability of test results from many companies and research groups in the United States. Most of the major conclusions of these different tests were the same. However, some minor differences have been found in the results of these experiments. Also, some of the conclusions related to the use of water heaters for direct load control were contradictory. In general, these results have been found satisfactory enough for the development of load models because they agree in most of the logical concepts and mathematical relations. The effort has been made to extract all needed information mathematical relationships from these tests and develop a model that is useful for the objectives of this research.

5.6.1 Developing the Database

Two databases have been created to assist the load model to generate the required output. The first data base contains required data about water heaters, while the second is used for air conditioners. Such data bases are not expected to be changed in a short period of time since they contain general information about the load shapes of water heaters and air conditions at different times of the year.

For water heaters, six load profiles have been generated for six periods of the year; [Jan/Feb/Mar/April], [May/June], [Jul/Aug], [Sep], [Oct/Nov] and [Dec]. For each period of these six periods it was found that the load profile is almost stable. Changes in temperature can move parts of load profile up or down but will not change the general shape of the curve. The main sources of data for developing these profiles were the test results of AEP and CP&L companies [23,24]. These two tests were considered because of the geographical location of the test area (in or close to Virginia).

For each of the six load profiles, the diversified hourly demand of a water heater and the average temperature at that hour were stored in the database. In other words, a typical daily load and temperature load curve were saved in the database. When the load model starts the process of generating the load profile of a water heater, it calls the database, pulls the required load profile and modifies it to include effects of changes in weather. Figure 23 illustrates the load profile for May and June.

Residential air conditioners are used in Summer and some hot days in Fall and Spring only. For this reason, one load profile was generated and stored in the database beside the data about temperature and humidity average values for such profile. To generate the load profile for any hot day, the basic load profile is pulled from the database, the actual hour-for-hour temperature and humidity values of the day are compared with those of the database and the required modifications to the load curve will be applied.

5.6.2 *Effect of Weather Conditions on the Load Profile of Water Heaters*

There are many meteorological factors that affect the shape of the load profile of water heaters. However, for a diversified demand of a large number of water heaters, one factor will mainly affect the load shape. This factor is the ambient temperature (in °F) of that hour. The ambient temperature affects the demand of water heaters through three means: losses, temperature of inlet water, and rate of usage of hot water to cold water by customers. It is a fact that whenever the temperature is low, the losses due to bad insulation are high. Also, the temperature of inlet water will be lower and requires a longer time to heat. People will consume more hot water in such cold conditions because they increase the percentage of hot water when mixed with cold water for their domestic uses.

In order to generate the diversified load shape of water heaters it was important to extract the rules and mathematical relationships between electric demand and ambient

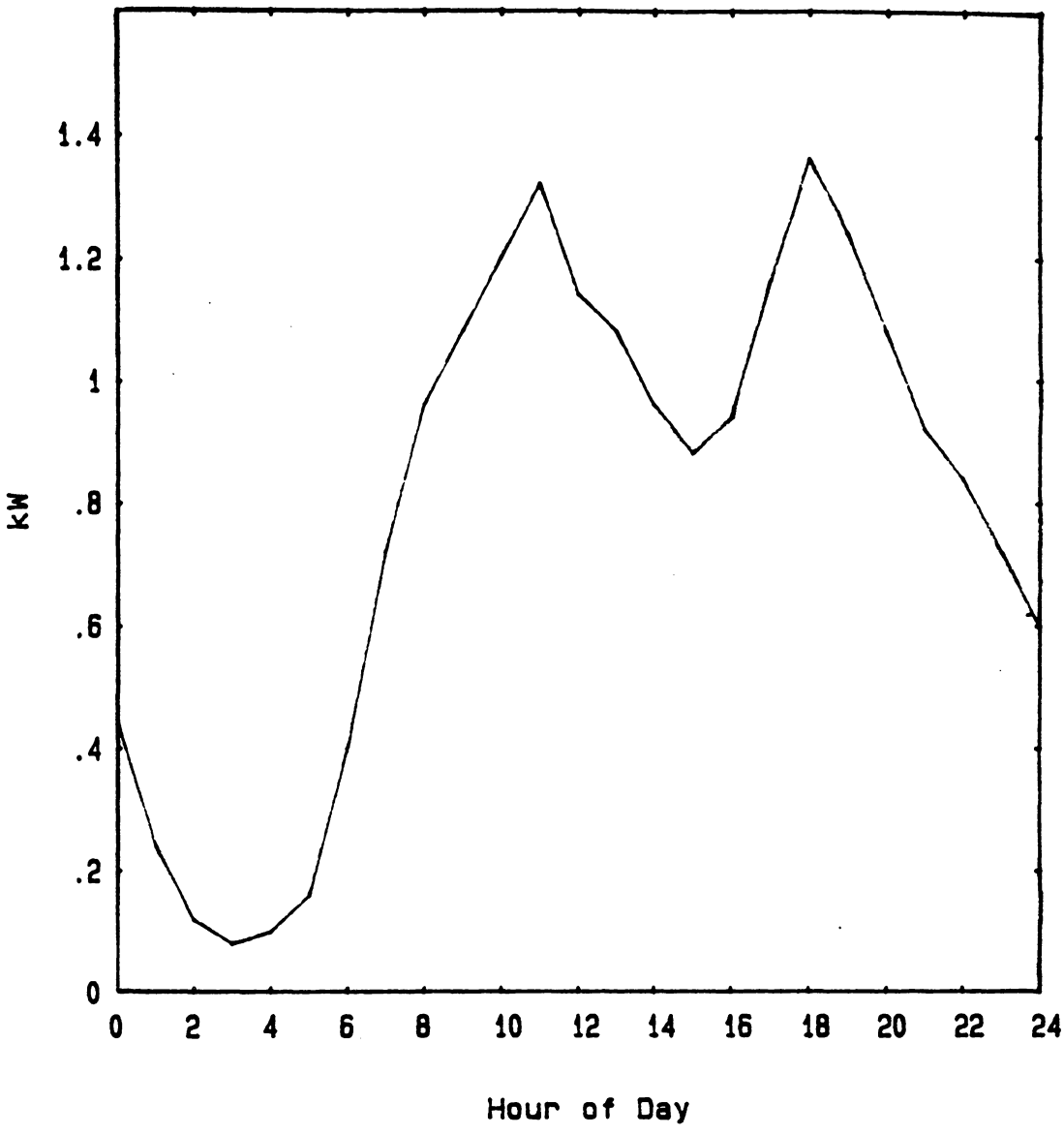


Figure 23. Typical load profile of water heater for May and June

temperature for the unit. The analysis of experimental results (available from different sources) could lead to the following rules.

1. for early hours of the day (1-5am) changes in temperature do not have a great effect on the electric demand of the water heater. For these hours most of the demand can be considered as the result of losses. These losses will increase when the ambient temperature decreases. For all of the six load profiles it was found that the following equation can describe the normal diversified demand of water heaters for hours (1-5am).

$$D.Demand_h = T.D.Demand_h \times \left[1 - .1 \times \frac{(temp_h - T.temp_h)}{20}\right] \quad (19)$$

where

$D.Demand_h$ = Diversified Demand at hour h for the required day (kW/unit)

$T.D.Demand_h$ = Typical Diversified Demand at hour h as defined in the database (kW/unit)

$temp_h$ = Temperature at hour h of the required day in °F.

$T.temp_h$ = Typical Temperature at hour h as defined in the database in °F.

2. For hours 6 to 11am the effect of changes in temperature has different effects on the local profile. The six load profiles were divided into two sets for this purpose; the first set has Jan./Feb./Mar./April, May/June, July/August and Oct./Nov., while the second has the remaining two profiles. For the first set, the following equation describes changes in demand of a single water heater.

$$D.Demand_h = T.D.Demand_h \times \left[1 - 0.05 \times \frac{(temp_h - T.temp_h)^{1.27}}{T.temp_h}\right] \quad (20)$$

where all variables are as above.

3. For hours 12 noon to 3pm and hours 9pm to midnight the following equation generates the load demand for any day

$$D.Demand_h = T.D.Demand_h \times \left[1 - .05 \times \frac{(temp_h - T.temp_h)^{1.1}}{16}\right] \quad (21)$$

where all variables are as above

4. Finally for the hours 4 to 8pm, the diversified demand of a water heater will be as follows

$$D.Demand_h = T.D.Demand_h \times \left[1 - .08 \times \frac{(temp_h - T.temp_h)^{1.34}}{T.temp_h}\right] \quad (22)$$

5. For weekends and holidays, the demand in the morning is less than that of working days, while for the hours just before and around noon will have a higher demand. Due to the lack of regularity in customer behaviors on weekends and holidays it is difficult to predict the exact shape of the profile. But as a general rule, the demand of water heaters on weekends and holidays is 45% less than weekdays for hours 6 to 8am, 15% less for hours 9 and 10am, and 25% more for hours 11 to 13.

5.6.3 Effect of Weather Conditions on the Load Profile of Air Conditioners

Two meteorological factors affect the electric demand of air conditioners - temperature and humidity. For residential applications, most of the air conditioners are not used to decrease the relative humidity of air as in the case of industrial and commercial applications. This does not mean that humidity has no effect on the total demand of the air conditioner, but it is not as high as expected. The AEP test on air-conditioners neglected the humidity effect because it was much less than the noise level in the diversified load.

Even though it is well known that some people keep their conditioners running during night time, the model developed in this study will not include night hours (9pm to 7am). This decision has been made because of lack of accurate results about night demand of air conditioners. Also, this demand is very low and hence impractical to be used for direct load control. The normal diversified load shape of the air conditioner is shown in figure 24.

This load pattern is the average for a typical day in Summer. For any hot day, this curve will be modified on an hourly basis depending on the temperature and humidity of that hour. In order to relate the increase (or decrease) in the demand of an air conditioner as a function of changes in weather conditions, the behavior of load characteristics of the load of air conditioners over a long period of time and for different areas was investigated. This analytical process could lead to some rules and mathematical formulations that can be used in developing the load model. These rules can be summarized by the following:

1. There is a certain temperature beyond which the total demand of air conditioners will reach saturation; i.e., the total demand will not increase if the temperature increases.

2. This temperature is not constant but it is a function of humidity. The Temperature-Humidity Index (THI) which is defined in equation (1), can be used to estimate the approximate value of this saturation point. A THI value of 89 can be considered the point beyond which the demand of air conditioners will reach saturation.

3. To generate the normal diversified demand of a single air conditioner for any day, the typical normal diversified load profile stored in the database will be modified to include the difference in weather conditions between that day and the typical day. This modification is done by evaluating the load difference (ΔL) due to differences in temperature and humidity. The mathematical relationship that describes these changes is as follows:

$$\Delta L(h) = \frac{[THI(h) - THI(h)_{Typical}]^{1.71}}{42.5} \qquad (23)$$

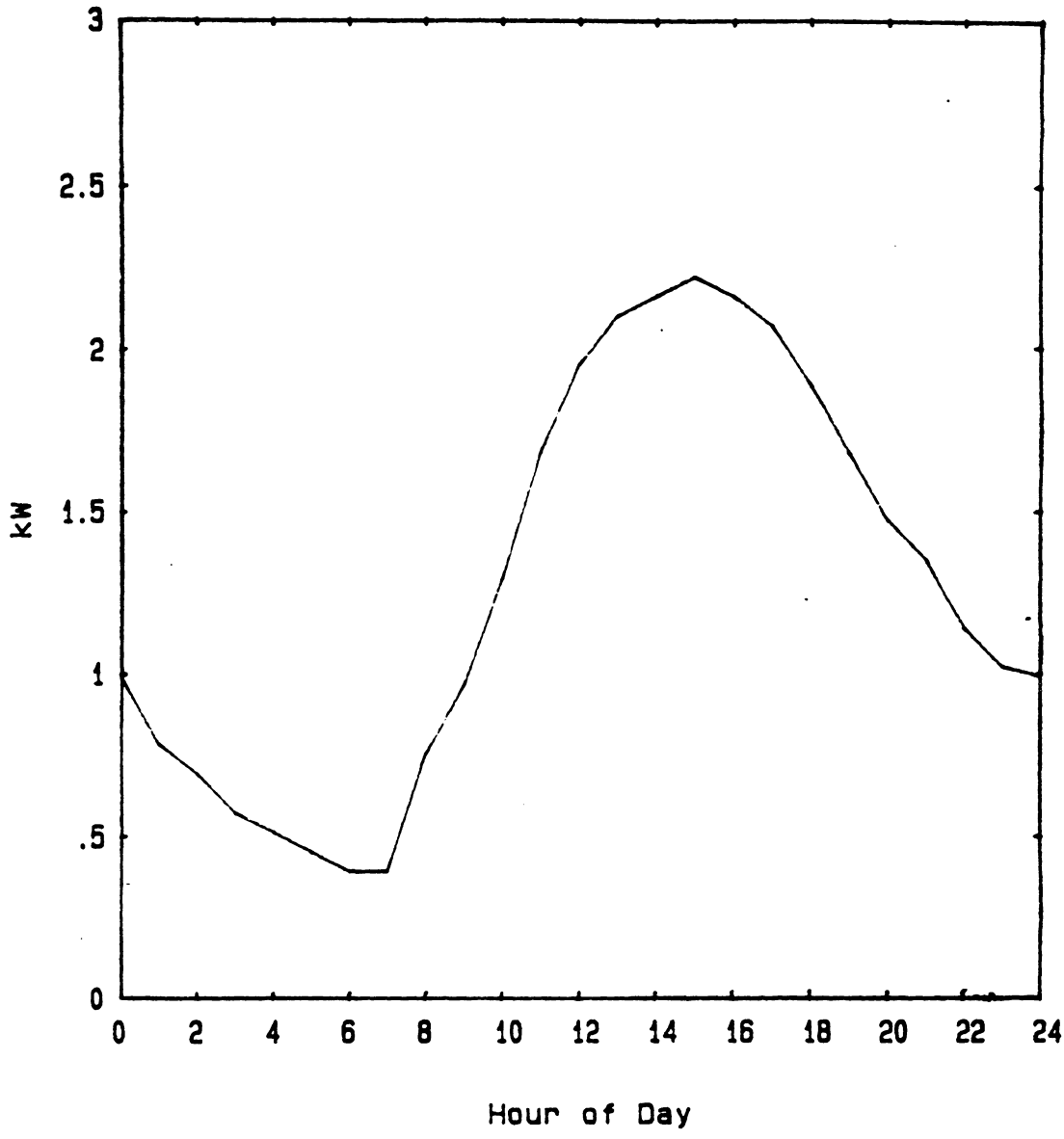


Figure 24. Normal diversified load profile of air conditioners in summer

$$\Delta L_{max}(h) = \text{Maximum Capacity}(h) - \text{Normal Diversified Demand}(h)$$

where

$THI(h)$ = Temperature Humidity Index at hour h of the required day.

$THI(h)_{Typical}$ = Temperature-Humidity index of the typical day as stored in the database.

$\Delta L(h)$ = Change in the load profile (in KW) from the typical load profile at hour h.

Maximum Capacity = The average maximum demand of all units under control ($\sim$4.5 kW)

5.7 Results

Load models developed during this study have shown the ability to generate the required information at a very high speed. The generation of predicted load reductions and payback due to certain control strategy requires less than three seconds of real time on the IBM-RT computer when the system is fully operational. The comparison between the predicted values and the experimental results, from other sources, have shown that the accuracy exceeds 95% in most cases for both water heaters and air conditioner models.

The following sections will discuss the general conclusions reached after the development of the load models. Most of these conclusions are related to direct load control. Therefore, the load peak hours will be considered to generalize these results.

5.7.1 Demand Reduction

- The potential demand reduction in winter is approximately 1.35 kW per water heater at the load peak hour if it is in the morning. If the load peak comes in the evening, the average reduction may drop to 1.15 kW per unit.

- In the summer, a demand reduction of 0.4 to 0.5 kW per water heater is expected at the load peak hour. Less contribution to the reduction is expected in days with extra high temperatures.

- In the fall and spring, water heaters contribute an average of 0.7 kW per unit. However, it is important to note that this reduction varies between 0.3 and 1.1 kW per unit depending on the time of load peak and weather conditions.

- Air conditioners have the potential to reduce the system load by an average of 0.8 kW per unit in summer at 60% cycling. This reduction can go up to 1.2 kW for hot workdays. The load reduction at the load peak hour depends on the cycling strategy, ambient temperature, first hour of control or not, and time of summer, spring or fall. In most cases maximum load reduction in water heaters can be achieved at the time of peak demand.

For hours other than the peak hour, different values of load reduction can be achieved. Fortunately, while the contribution of water heaters to load reduction is minimal at load peak hours in winter, it is maximum for air conditioners. Blocks of water heaters and air conditioners can be used for combined control for the load peak reduction in summer. However, water heaters can be shut off for several hours without causing trouble to the customers. Such operation can not be applied for air conditioners.

5.7.2 *Payback Demand*

Different factors affect the total magnitude of the restrike demand. Time of the day and the length of the control period are the major factors in this regard. Previous investigations have lead to the development of some empirical formulas relating the total payback demand to the total deferred energy [24]. These formulas don't estimate the length of the payback period nor the increase in demand during the first hour following the control period. Moreover, the uncertainty in the estimates can go up to 70% in some cases.

In this study, some empirical formulas were developed in order to provide sufficient and important information about the total restrike demand and the restrike demand in the first hour following the control. The reason for the emphasis on the first hour is the possibility of having an unpredictable increase in demand during that hour to the point it might create a new load peak. The general conclusions that could be reached related to the payback demand can be summarized in the following:-

- The length of the restrike demand ranges between one hour and a number of hours equal to the number of control hours for water heaters. This length usually depends on the normal diversified demand at the hour(s) following the control period. If the average demand at the first few hours was high then there is a good chance that the water heaters will reach the saturation point at the first hour, and also, maybe the second hour. Generally the payback period will not exceed three hours in most cases.

- For air conditioners, usually there is a payback following the first hour of control until one hour or more after the control period. Since the load reduction during the control period (other than the first hour), is much higher than the payback of previous hour, it will appear as a decrease in reduction only. In most cases the payback demand following the control period will last less than half the control period, and in many cases will not exceed an hour. If a high cycling rate (60 or 70%) was used, the length of the payback period will

increase. In such cases, most of the air conditioners will reach the saturation point in the first two hours when the control is over. This means that this equipment will continue to run for several hours without stop if the temperature is very high.

- The total restrike demand of water heaters following a control period of n hours can be related to the total deferred energy (E) and the reduction of the last hour using the following empirical formulas:-

for winter

$$PB = .853 \times R_n + 1.741 \times \left(\sum_{h=1}^{n} R_h\right) - .333 \times \left(\sum_{h=1}^{n} R_h\right)^2 \qquad (24)$$

$$PB_{max} = 2.7$$

for summer

$$PB = .34 \times R_n + .753 \times \left(\sum_{h=1}^{n} R_h\right) - .032 \times \left(\sum_{h=1}^{n} R_h\right)^2 \qquad (25)$$

$$PB_{max} = 1.9$$

where

PB = Total payback demand

R_h = Reduction at hour number h of the control period

R_n = Reduction at last hour of the control period

n = Total number of hours of the control period.

- The restrike demand in the first hour following the control period can be described using the following empirical formula

$$PB_1 = .33 \times R_n + 1.34 \times \left(\sum_{h=1}^{n} R_h\right) - .56 \times \left(\sum_{h=1}^{n} R_h\right)^2 \quad (26)$$

$$PB_{1\,max} = 2.0 - D_{n+1}$$

where

PB_1 = Payback demand at first hour following the control

D_{n+1} = Normal diversified demand at the first hour after control

- For air conditioners, the payback period usually does not exceed the control period and, in most cases, less or equal to three hours. The most important feature in the payback demand of air conditioners is the fact that this equipment reaches the saturation level in most cases in the first hour following the control period. For this reason, no empirical formula will be given for the first hour of the payback since it equals the total reduction or the amount needed to reach the saturation level, whichever is the smallest.

  The total restrike can be related to the total deferred energy and the reduction during the last hour by the following equation

$$PB = 2.0 \times D_n + .333 \times \left(\sum_{h=1}^{n} R_h\right) \quad (27)$$

Chapter VI

DIRECT LOAD CONTROL DISPATCH

Direct control of customer loads is the load management option with the widest applicability. As it was mentioned earlier in chapter I, the Europeans have used direct load control in space heating and water heating for years. In the U.S., recent surveys of load management projects have shown a great interest in using communications and load control [25].

Clearly, there is a great interest in direct load control as a tool whereby the utility can modify the overall system load profile to improve the efficiency of the power system. Also, large customers (electrical cooperatives) are very interested in using direct control to reduce their share in the system peak. This conclusion is reinforced by some utility's policies of charging for "coincidental peak", or the widespread use of interruptible contract rates whereby an industry agrees to shutdown certain nonessential loads in response to a signal from the electric utility.

6.1 Approaches to Load Control

Two approaches can be taken towards direct control of customer loads: passive and active. Passive control is that approach where timers and temperature sensitive switches are used to control certain loads without any direct control over it by the utility. Time or temperature differentiated rates are the incentives for the customer to use such devices. This approach has limited usefulness, and the utility has no guarantee that some loads will be removed from the system peak. Also, this type of control cannot be integrated with the system planning process, or even integrate it with the control system center for dealing with abnormal conditions.

The active load control system consists of a communication line between the utility and specific customer loads. A number of communication alternatives, including radio, ripple, and power line carriers, are available in the market. As it was shown in the last chapter, loads that will be considered for this type must have inherent or designed storage characteristics, or are nonessential, in order to minimize customer inconvenience.

An active load control system is more flexible than a passive one because it is not limited to one operating mode. An operating strategy which considers load dispatching as an alternative to power dispatching, subject to constraints on the power system (e.g. system security, and energy limitations), and considering the operational characteristics and constraints on the load being under control, is a more realistic approach.

The active control system allows the utility to "dispatch" load depending on the conditions of the system. Since each system has unique characteristics, then it is important to consider these characteristics when planning its operation. The integration of the active load management system into the operation of the power system will be discussed in detail in chapter VII.

6.2 Control Strategies

The load control strategy is the plan for controlling the loads. The important factors in the control strategy are the hours when that control is applied and the cycling strategy. The hours of control generally coincide with the peak load hours on the utility system and generally extend for several hours before and after the peak hour(s). During the period, the device load is generally lower than what it would have been, if there was no control.

Basically, there are two control options (strategies) which can be used to control residential loads - payback and cycling. The payback control strategy can be employed by disconnecting all loads simultaneously for extended periods of time. This can be accomplished by sending signals to the radio operating switches to shut-off some of the customer loads on a regular basis over a period of time, so that the devices are disconnected during the entire control interval. After restoring these loads back, the demand of these devices will exceed that of the normal diversified patterns of these devices. This increase in demand is commonly referred to by "payback" or "restrike" demand. The magnitude and period of the restrike demand are of great importance in deciding upon the control strategy and the length of control interval. Payback strategy can be used for long periods of time for some devices without affecting the customer's perception of comfort (e.g. water heaters can be controlled up to six hours). However, other devices cannot be shut-off for long periods of time without creating inconveniencies to the customers. For example, the residential air conditioners cannot be turned off for more than an hour in any case, and for not more than 30 minutes in most cases.

The cycling strategy is the pattern of control signals sent to the loads under control (usually air conditioners). The most common cycling strategy is one in which the device unit is turned on and off several times in an hour. Cycling strategy can be employed by transmitting periodic signals in a pattern whereby a given percentage of the available devices are switched off for a given period of time. The percent of time the machine is off in one hour

represents the cycling strategy. Load shedding, the practice of shutting the device unit off for the whole hour, would be represented by 100% cycling strategy. If a certain device is cycled on and off every 15 minutes over a one-hour period, the machine would have been unable to operate for one-half hour, or 50% of the time. A different cycling pattern, cycling the unit on and off every 7.5 minutes, would also represent a 50% cycling strategy. Differences in the cycling pattern for a given control strategy do not generally change the calculation of diversified load impact. Developing a cycling sequence which can reduce the demand while causing little inconvenience to the customer is the major objective of this strategy.

6.2.1 Impact of Payback Demand

The load during the first several hours after control is different from the load during other non-control hours. For a control period of several hours, it is likely that the residential requirements were not fully met due to the cycling of the units. When the cycling period is completed, the units are free to meet these requirements that had been building up during the hours of control. Because of this, most machines will come back on as soon as control is dropped and stay on for longer periods of time than normal.

When control is discontinued, generally there will be a relatively undiversified spike in the device load, and the load may continue for several hours to be at an elevated level. The natural diversity of the loads will return as soon as the residential requirements are satisfied. The satisfaction of these requirements may require several hours to be completed.

The cycling strategy can be applied in one of the two types: smart duty cycling or the conventional cycling. The smart duty cycler is a microprocessor based cycler that continually monitors the air conditioner duty cycle. The on-time and off-time each makeup one-half of the duty cycle. Upon receiving the radio signal, the smart duty cycler restricts the air conditioner operation to the most recent duty cycle recorded. Each unique equipment will have its unique duty cycle. This method helps in maintaining the natural diversity of its control group.

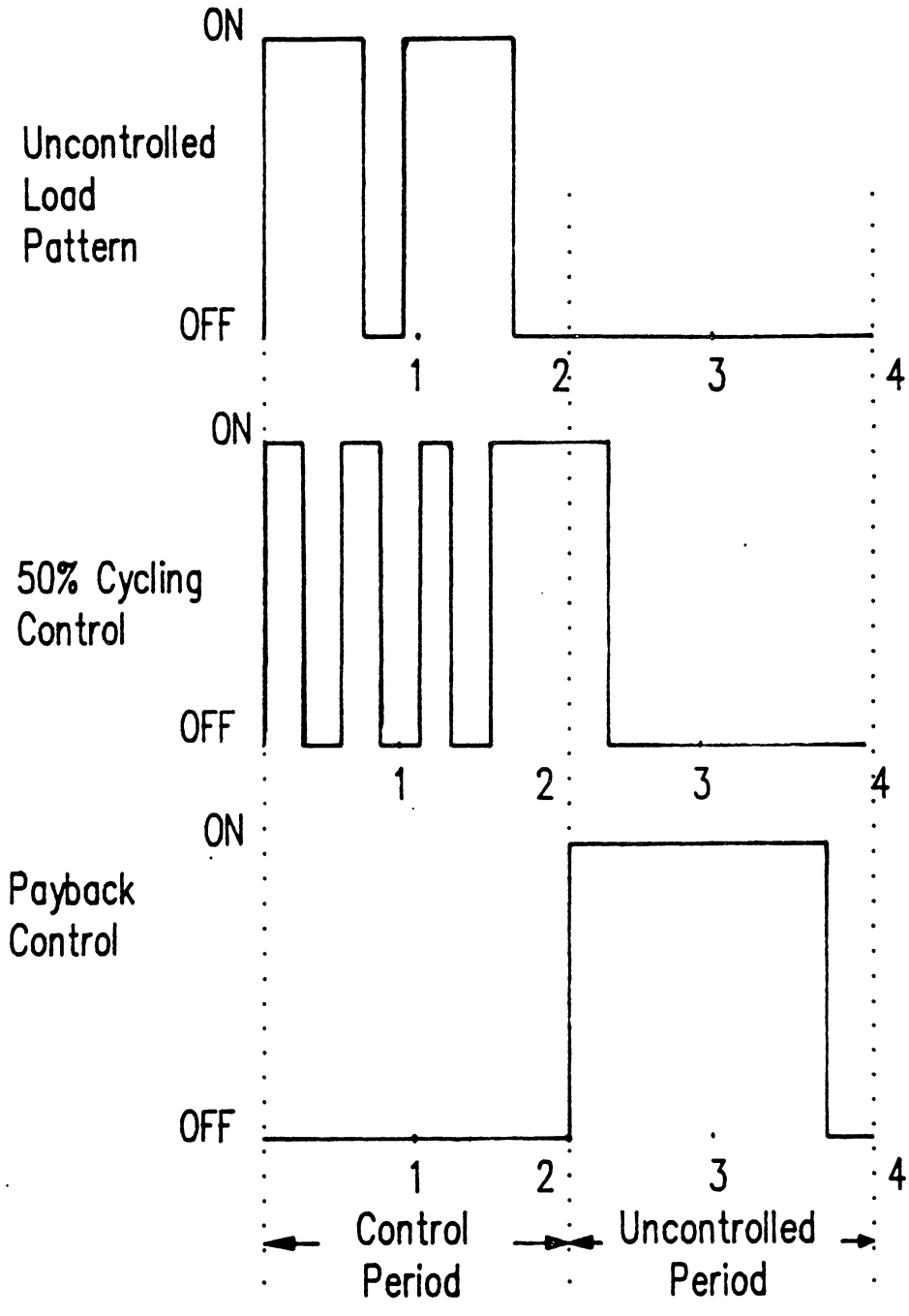


Figure 25. Load pattern on a typical load device under uncontrolled, cycling control, and payback control conditions

The conventional cycling group had its air conditioners interrupted according to a predetermined cycling strategy ranging between 30 and 60%. In most cases, this strategy is implemented between 2:00 p.m. and 8:00 p.m. on weekdays. The control process can be activated when a signal is transmitted or by using sensors that activate the controllers if the temperature reaches a certain limit (90°F for example).

6.2.2 First Hour of Control

For most residential loads, the first hour of control is different from load in other hours of control because of the way the cycling strategies are implemented. As much as possible, the utility will try to maintain some diversity of the residential load by ramping the cycling strategies among participating groups. If the participant groups were not staggered, all the machines under control would come on and off at the same time, causing load spikes that increase peak load.

To reduce the impact of direct load control in the first hour of control, electric utilities usually ramp the loads into several groups. In the first half-hour, 25% of the groups are switched off, meanwhile in the second half and the remaining hours of control. The idea of ramping the groups of loads is illustrated in figure 26.

6.3 Factors Affecting the Selection of Control Strategy

In most control programs, both control strategies are used in order to achieve the optimal control. How to combine these two strategies in one program is one of the most difficult decisions in the whole process. Before discussing the details of the algorithm of initiating the control program it is essential to define all factors and variables that affect this selection. The following are the major factors:

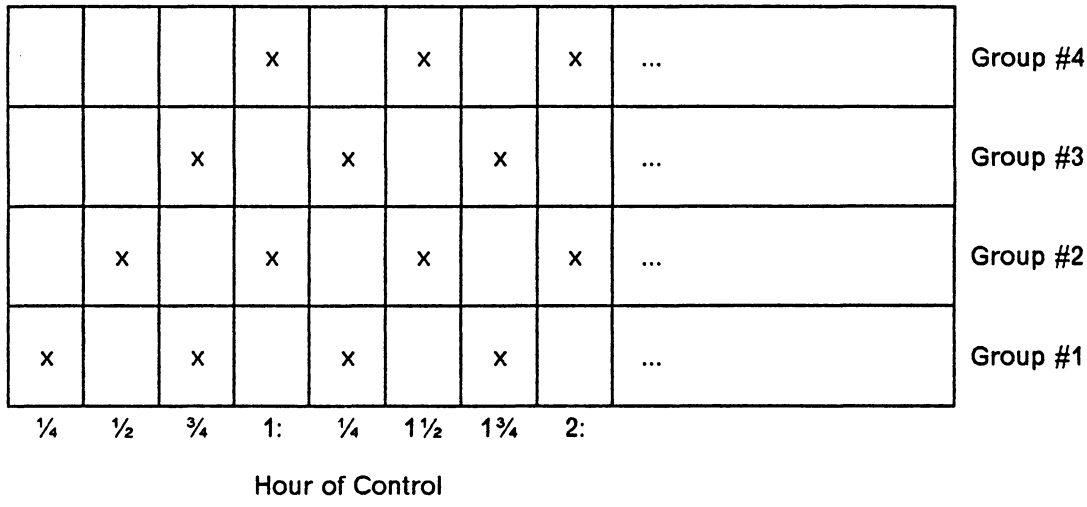


Figure 26. Ramping the groups of loads

1. Season: in winter only water heaters (and in special cases space heaters) can be controlled. If water heaters were considered, only then the payback strategy will be used for the whole period.

2. Weather Conditions: for different days in the same season with different weather conditions, different control programs will be used. The amount of load that can be shed depends on the weather conditions of that day and consequently on the control strategy.

3. Time and period of control: different load control options can be used for different times of the day. If the peak was in the morning, then it is usually sharp and lasts for a short period of time. Flat peaks in the afternoon usually require different control options.

4. Total reduction in demand required: based on the amount of load to be shed, the system (or the operator) will decide on the option with the optimal reduction.

5. Customer's perception of comfort: one of the major objectives of load control is to avoid the customer's inconvenience. Previous tests [7,8] have shown that the season, weather conditions, time of control and its length affect, the number of hours and the cycling percentage with which the customer will feel uncomfortable due to load control.

6. Total number of signals to be transmitted: as it was shown before, availability of loads under control is always less than one because some of the radio switches are faulty. It is of great importance to reduce the total amount of signals sent to each radio switch (in the cycling strategy) in order to reduce the probability of failure.

6.4 Load Control Models

Any model of load control operating strategies must consider the communications and control systems that are available for implementing the control strategies. Also, the system designer and operator must utilize the knowledge of load characteristics and load control systems. The problem of selecting the proper control strategy can be converted into a mathematical problem which can be solved using a numerical method, or can be converted into a decision making problem which can be solved using an expert system.

First, the problem can be stated as follows:-

- Optimize total load reduction at peak hour.
- Minimize the restrike demand following the control.
- Restrike demand can be equal or less than a certain limit.
- Minimize number of signals sent to the switches.
- Minimize total number of control hours to avoid customer inconvenience.
- Total number of control hours can reach certain limits for each season.

From the above, it is clear that the main objective of the control models is to obtain an optimal reduction at peak hours, and at the same time avoid some problems. These problems include the elimination of the possibility of creating a new peak due to restrike demand, avoid decreasing the availability factor by reducing number of transmitted signals, and minimizing the customer's inconvenience by reducing the number of control hours. Some of the above points are objective functions, while others are just constraints. In order to achieve the

optimality of these functions using numerical algorithms, it is important to describe the problem mathematically.

The objective function is

$$R_{Total} = \max \sum_{i=1}^{n} [h_1 \times R_1(i) + h_2 \times R_2(i)] \tag{28}$$

$$R_{Total} \leq R_{max}$$

$$P_{Total} = \min \sum_{i=1}^{n} [p_1(i) + P_2(i)] \tag{29}$$

$$P_{Total} \leq P_{max}$$

$$h_1 \leq h_{1\,max}$$

$$h_2 \leq h_{2\,max}$$

where

R_{Total} = Total load reduction at peak hours.

P_{Total} = Total payback at first hour after control.

$R_1(i)$ = Reduction of unit (or block) i due to control strategy #1.

$R_2(i)$ = Reduction of unit (or block) i due to control strategy #2.

h_1 = Number of load control hours using strategy #1.

h_2 = Number of load control hours using strategy #2.

n = Total number of load units or blocks.

The value of n is usually high, and depends on the type of available loads and the geographical distribution of the loads.

The above mathematical representation of the problem has the same form as the linear programming problems. Currently most of the load control strategy programs are using the linear programming method to solve the above problem [1]. For a large number of load

blocks, the linear programming algorithm may require a large number of iteration before reaching the optimal solution for the problem, and hence, require a long run-time period on the microcomputer. Such a requirement does not suit the the design of the intelligent and integral load management system. For this reason, the author found himself in need of a new approach to the problem. For compatibility, and at the same time efficiency, the expert system approach was used to solve this problem.

The main structure of the expert system-based load control model includes the rule base, database, and the inference engine with other processes on the system. The algorithms used for generating the optimal load reduction are discussed in the following.

Rule 1. For winter, water heaters are the only loads available for control. For summer, air conditioners are available for control in addition to water heaters.

Rule 2. For air conditioners, the cycling strategy is the only one to be used for controlling these devices. For short control periods (less than two hours), the cycling can go up to 70%. For longer periods, lower cycling percentages must be used.

Rule 3. Payback strategy can be used with water heaters for up to four consecutive hours in summer, and three hours in winter for days with extra demand.

Rule 4. After the generation of the 24-hour load forecast, define the peak hour where maximum reduction is needed, and the period where the threshold value is exceeded.

Rule 5. The control period does not include the load peak duration only, also it remains in action for sometime after that. The length of the extra period is a function of the payback demand, the load shape of the total system load, and the accuracy of the load forecast.

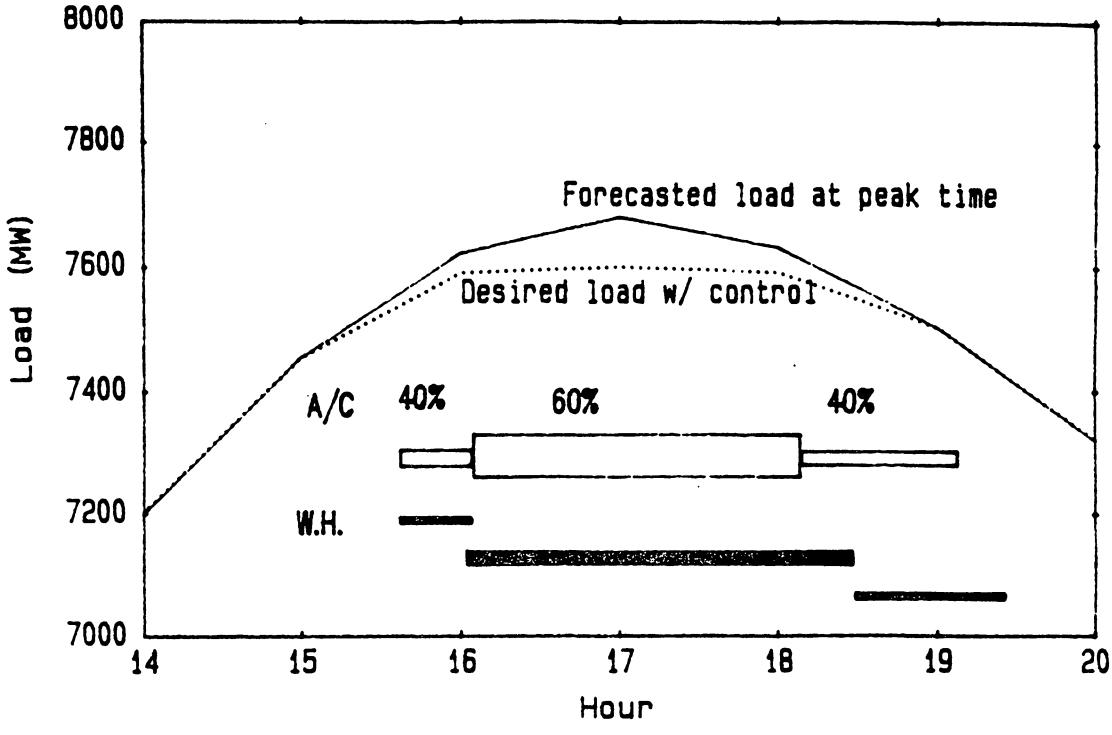
Rule 6. The maximum load shed must occur at the peak hour. Hours preceding or following that hour will also have load reductions.

Rule 7. Selecting the load strategy will be based upon the distribution of load reduction over the control period. If the peak load requires maximum reduction (i.e., total load shed of all available units), some load blocks will be controlled before the peak hour, all blocks at the peak hour, and the remaining blocks after that. Figure 27 illustrates this method.

Rule 8. For Summer peak days, where a flat peak exists for several hours, a combination of the payback strategy and the cycling strategy will be used. For early hours of the control period, low duty cycling (30-40%) will be used for air conditioners. At the peak hour, a higher duty cycling strategy (40-70%) will be used for an hour or less accompanied by total load control of water heater blocks. When the peak hour is passed, water heaters will be restored gradually and the duty cycle will be reduced in a manner to avoid unexpected increase in demand due to restrike demand.

Rule 9. Since there is a certain percentage of error in load forecast, this algorithm will keep watching the changes in demand. This action will help in preventing bad decisions based on erroneous load forecast.

Rule 10. If the utility is concerned about the hourly load average, not the instantaneous or short-term load average (few minutes), then the load control for the first and last does not require cutting the load for the whole hour. The control algorithm will determine the number of load blocks and how many minutes are needed to reduce the average hourly load for the required level. Such an approach will help in reducing the length of the control period while maintaining the load magnitude at a certain level. For example, if the total amount of reduction needed for the first hour was 15 MW, then the controller will shed 75 MW for the last 12 minutes of that hour instead of cutting



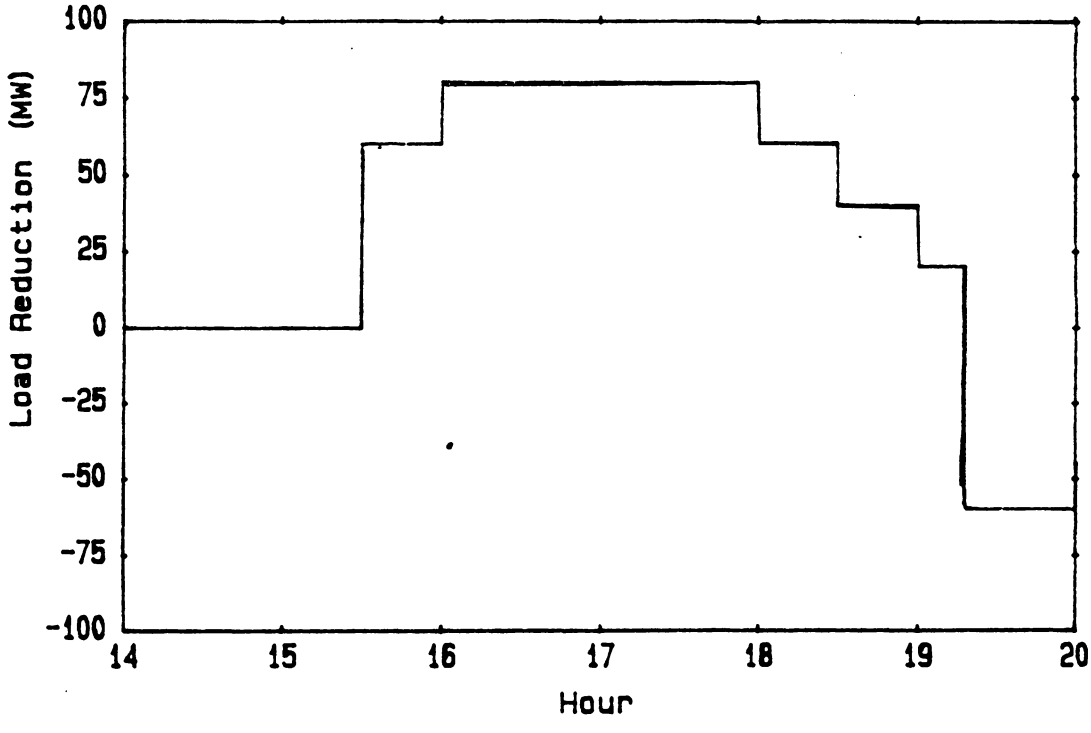


Figure 27. Optimization of peak load reduction on a flat-peak day

15 MW for the whole hour. The payback demand must be taken into consideration in this process so that no serious effect will occur for the following hours.

6.5 Determination of Threshold Value

Threshold load value is used to help the system decide whether to dispatch direct load control or not if a new monthly peak has been forecasted. The dispatch of direct load control must be limited to a certain number within any month in order to minimize the possibility of customer inconvenience. However, since it is difficult to decide with high certainty that the new forecasted peak is a monthly peak, then the threshold value must be evaluated carefully in order to guarantee that the actual monthly peak will not be missed, and load control will be activated for that peak. In general, most of the electric utilities and wholesale customers limit the number of times for dispatching load control to 5 times per month.

There are two ways to decide upon the load threshold value. The first, is to use long-term load forecast to predict the magnitude and time of the monthly peak. The threshold value in this case will be a little bit lower than the forecasted monthly peak. The second, is to use historical monthly load peak values for the last few years in order to approximate the threshold value. The first method might look more accurate for the first time, but actually this is not the case. So far, it is very difficult to generate an accurate long-term forecast. The errors in load forecasts for more than a week will jump to high percentages if weather forecasts are not very accurate. In addition to that, most of the available long-term load forecast programs require huge databases, and require very long run-time on the computer. For this reason, the second method was used for this system.

The monthly load peaks for the last five years have been archived in a database. At the end of each month the new monthly peak will replace the oldest monthly load peak in order to limit the number of reference years to five. If the weather forecast to the end of the month is available with good confidence, then the value of the monthly peak with closest weather

conditions to the forecasted (severe) weather conditions of the month will be selected. If that peak has happened in one of the last three years, the threshold value will equal that monthly load peak multiplied by 0.85, and if it happened more than three years ago then that peak will be multiplied by 0.95. If no long-term weather forecast is available, then the minimum monthly load peak for the last three years will be selected and multiplied by 0.95 to give the threshold value. If the threshold value has been exceeded by the load value at anytime during the month, the new monthly load peak will replace the threshold value.

6.6 Generating the Modified Forecast

When load control is activated, the total system load will be reduced from what has been forecasted. Comparing the load forecast with the actual load data when the control process is over, will show huge discrepancies between them at the control time and just after it. Clearly, the reason for that is the forced changes in demand due to load control and restrike demand. For this reason, in order to avoid misjudging the accuracy of the load forecast program, the load control algorithm will generate a modified load forecast. This forecast will be calculated by subtracting load reductions at control time from the original forecast and adding the payback demand for the hours following that period. The generation of this modified load forecast will be done after the whole control program has been planned and the load models have been used to estimate the reductions and paybacks.

Figure 28 illustrates a sample of the modified load forecast program. Note that the load at hours preceding load control will remain the same. The accuracy of the modified forecasts depends on the accuracy of the original forecast, the ability of load models to estimate the reductions and paybacks, and the success of the system to carry out the control plan.

Modified
24-Hour Load Forecast

hour	Load w/o DLC		Load w/ DLC	
0:00	5772	MW	5772	MW
1:00	5612		5612	
2:00	5664		5664	
3:00	5698		5698	
4:00	5850		5850	
5:00	6309		6309	
6:00	7363		7363	
7:00	7972		7870	Red
8:00	7899		7865	Red
9:00	7665		7734	Pbk
10:00	7401		7447	Pbk
11:00	7198		7206	Pbk
12:00	6862		6862	
13:00	6681		6681	
14:00	6546		6546	
15:00	6548		6548	
16:00	6838		6838	
17:00	7329		7329	
18:00	7591		7591	
19:00	7384		7384	
20:00	7132		7132	
21:00	6805		6805	
22:00	6295		6295	
23:00	5775		5775	

Date: 1/20/1986
Time Now: 9:47:22

Figure 28. Sample output of modified load forecast

Chapter VII

INTEGRATION OF LOAD MANAGEMENT INTO UTILITY PLANNING AND CONTROL

The integration of demand-side management in general, and load management in particular, is an important topic. Most of the electric utilities are experiencing a change from supply-side management strategies to demand-side ones. The switch began with the cancellation of planned generating units and the substitution of load management and conservation programs. This transition has required significant adaptive changes in utility planning. The new planning process has been attempting to incorporate these changes by:

1. addressing questions of how to handle cogeneration, interruptible loads, conservation;

2. changing the load forecasts to reflect changes in basic patterns of electricity usage and the uncertainty in the forecasts; and

3. involving other organizations within the utility in order to include the customer behavior.

However, the integration of load management into the planning process must incorporate four basic criteria [27] as follows:

1. Technical: which includes feasibility, reliability and operating impacts.

2. Economic: the economic evaluation is primarily based on the cumulative present worth of incremental revenue requirements for each alternative plan from both long-term and short-term perspective.

3. Flexibility: the study of the robustness and adaptability of the plans under a wide range of uncertain conditions through sensitivity analysis.

4. Capital Spending: this addresses the financial feasibility of a plan and its capital spending and associated allowance for funds used during construction as well as implications on customer revenue requirement.

7.1 How to Integrate Load Management into the Planning Process

Several distinct ways can be used to integrate load management into the planning process. These can be grouped into two major categories:

1. Incorporate load management into energy forecast.

2. Incorporate load management as a capacity option.

In the first method, decisions concerning load management are made independently of the basic planning process. The energy forecast is made as usual without regard to utility intervention in the market place. Subsequent forecasts are made of each load management activity. After this, the planner will review the capacity plan as currently envisioned. This review will reveal potential load shape modifications which should help utilities direct their analysis, and hence select their best candidates. The following figure summarizes this method which has been recommended by the Load Management Subcommittee and the System Planning Subcommittee of the IEEE [28].

The preliminary desirable load shape change can be developed using marketing and implementation plans. These plans include projected incentives and customer acceptance. The magnitude of these incentives and the resultant customer acceptance and their response is based on estimates and forecasts of behavior. Following this step, a more detailed load shape can be predicted, production costs evaluated and the overall structure of incentives is reviewed. The iteration of this process can yield to the formulation of a load management plan.

The second method of incorporating load management into the planning process involves incorporating load management directly as a capacity option. In this case, two options are available for evaluation of this method. The first centers on the interruptible and peak reduction options to obtain capacity benefits. The second method concentrates on the study of energy savings.

7.2 Applications of Integration LM into the Planning Process

Benefits of load management can exceed peak reduction to include valley filling as well as selective sales of energy. Such additional capabilities of load management have not been

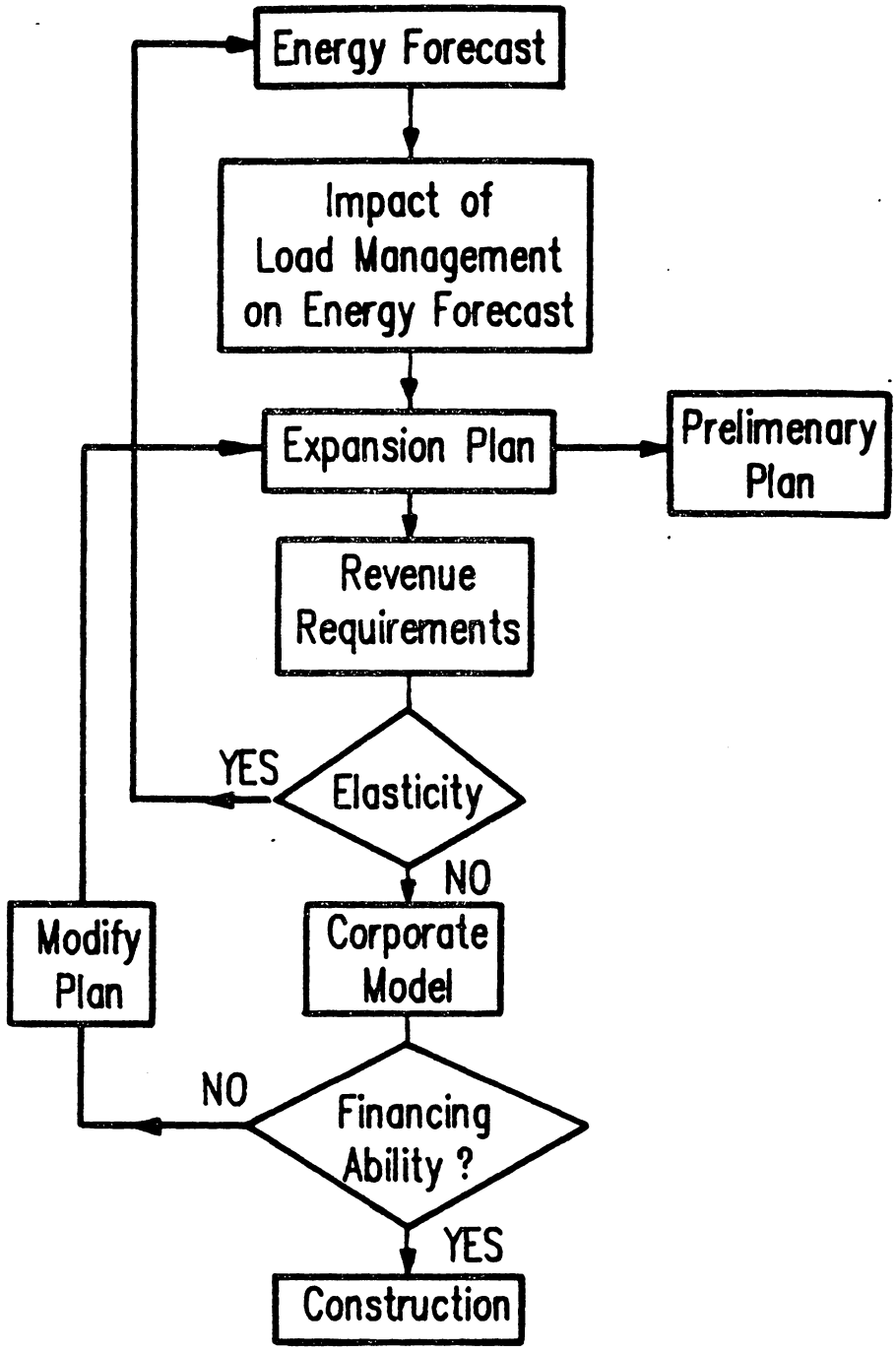


Figure 29. Process of integrating load management into the planning process

considered because the planning process has not been adequately developed. This is because the need for a fully integrated planning process never existed in the past.

Energy forecasts prepared by traditional planning processes could not reflect the impact of load management.

However, it is important to notice that the role of load management is changing, and hence, introducing new uncertainties concerning its capability, availability, liability and its effect on reserve requirements. This fact motivates the concern about the adaptation of new tools for integration of load management into the planning process.

The integration of load management into the planning process has many practical and potential applications. Peak clipping and valley filling are the main application of load management in the planning process. In addition to that there is a need to consider the impacts of the load management for every hour of the year. Some of the available options to include the integration of load management into system planning are:

1. Optimize unit commitment scheduling

2. Provide an emergency reserve for the utility

3. Optimize production costs

4. Maintain minimum system load for off-peak hours

5. Increase utility sales through promotions.

These options produce impacts which overlap different activities of the planning department. This requires the development of a 'strategic plan' in order to establish long-range direction for tactical load management planning. The tactical aspects of the load management planning process proceeds as follows:

- Develop the targets of load management based on the market research information.

- Develop a new adaptive energy forecast which incorporates the load management targets and impacts.

- Develop a modified generation expansion plan by utilizing the new load forecasts and load management targets.

- Forecast the long-range finances which incorporate the load forecasts, projections of operation and maintenance expenses, and the generation expansion plans.

The load management planning process described above, if carried out properly, can produce a balanced strategy which emphasizes both peak load reduction and off-peak sales. This strategy will increase the utilization of existing generation facilities while reducing the need for new generation [28].

7.3 Factors for Integrating Load Management

Though the published literature on this subject is very limited, some articles did address some of these issues. One paper, by the IEEE Working Group on Current Operational Problems [29] discusses the issue of using load control as a operational tool and regarding it as an operating reserve to compensate for rapid load changes. Papers by Lee and Breipohl [30] and Le et al. [31] suggested that load control could help meet system spinning reserve. Bischke and Sella [32] proposed to use Kalman filtering and advanced automatic generation control for dispatching water heater control programs. Concerns were expressed over how load control could affect system transient stability, which could happen if the degree of load penetration is high [28]. Chan, et al. [33] suggest the following advantages for integrating load control into power system control centers operations:

- common machine interface displays for load control;

- common data acquisition procedures;

- and "piggy-backing" on the acquisition system for load control applications.

7.3.1 Factors Affecting the Integration

Four major factors have direct impacts on the formulation of the method for integrating load management into power systems control and planning:

a) load management operational objectives,

b) limits on the total number of days for load control

c) impacts on power system control and planning; and

d) penetration levels of load control.

(a) Load Management Operational Objectives

There are five distinct load management operational objectives which are representative of the industry [34]. These five objectives are the following:

- Real-time dispatch: controlling the load in real-time to improve the economics of the system. No planning is done to schedule resources ahead of time.

- Coordination with scheduled loads: controlling the load to counter the effects of large blocks of load that can be scheduled.

- Improved System Operations on Normal Days: controlling the load on a daily basis to reduce operating costs and lost revenue by deferring the start-up of cycling and

peaking units. Scheduling of load management coordinating with unit commitment schedules.

- Improved System Operations on Selected Days: same as above except that it is done for days that are forecasted to have high production costs, such as system peak days.

- System Emergencies: to invoke load management to handle system emergencies such as unexpected generation shortfalls.

(b) Limits on Total Number of Control Days

Whether or not there are limits on the total number of days that load management can be used is an important factor. Existence of such limits, in some cases, establishes the utility's objective for controlling the load. For example, if there are tight limits on the total number of days with load control, then the utility may want to obtain the most benefit by controlling the load only on system peak days or on days when operating costs are at their highest.

In the same way, tight limits on total number of days for load control may preclude some of the load control objectives identified previously. The findings from the utility survey [34] showed that in cases where only a small number of load control days were allowed, the operators would tend to use load control only for emergencies. Therefore, constraints on the total number of days will require analysis programs to optimally allocate these limited resources.

(c) Impacts on Power System Control and Planning

A decision-support system affects some of programs of the Power System Control and Planning programs. The primary impacts will be on load forecasting and scheduling programs. The load forecasting programs must have the ability to account for the effects of load control. The degree of modifications will depend on the algorithms and techniques used

for forecasting the load. The rule-based algorithm developed during the design of the Intelligent and Integrated Load Management System has solved this problem with minimal modifications. Only the effects due to load reduction and energy payback were added to the load forecast to obtain the net system load forecast.

Scheduling programs such as Unit Commitment, Hydro-Thermal Coordination and other programs will be affected by load management. The modifications required for these programs will range from simple modifications of the input load pattern to more complex techniques of including load management in the optimization formulation.

However, some programs such as the conventional Generation Dispatching (i.e., Automatic Generation Control and Economic Dispatch Calculation) will not be affected. These programs will simply accommodate load management as part of the routine random fluctuations in the system load.

Also, if load management is used as a part of operating reserves, the programs for monitoring, calculating and allocating reserves will have to be modified. Other programs such as State Estimator, Penalty Factors Calculations and Security Analysis may require minimal or no modifications.

(d) Penetration Levels of Load Management

Effects of lower penetration levels of load management will be masked by the noise in the system and by the level of inaccuracies in the forecasting and analysis techniques. Therefore, the integration of load management into the power system operations should only be attempted when the penetration level of load management makes the analysis meaningful.

7.3.2 Retrofit and Implementation Constraints

Retrofit and implementation constraints are those factors that will affect the practical implementations of load management integration into existing power system control centers.

Most of these constraints can be eliminated by using the information technology to integrate the power control system with the load control system.

Three major factors affect the implementation of the load management system with the power system control center:

- Power system control center should be able to accommodate software changes required for the integration of the two systems. Programming tools and the personnel should be readily available to create new computer codes. Also, the licensing agreement from the system vendors should allow the required modifications.

- For utilities with separate computers for load management and power control, a special interface between the computers will have to established.

- If a separate computer for load control applications is used, the system operator should be able to access the computer through the same CRT displays used for the power control system application. This will allow the proper integration of the two systems.

Chapter VIII

SIMULATION OF THE IILMS

After completing the design of the intelligent and integrated load management system (IILMS), a typical daily operation of the system was simulated. A network of computers, terminals, modems and other communication devices were used to install the system at the Energy Systems Research Laboratory at Virginia Tech. While some of these devices carried out normal operations, others were used to emulate the operation of other equipment such as data sources.

Actual weather and load data of Virginia Power for 1986 were used for the simulation process. This simulation process was done in two modes: real time and accelerated time. In the accelerated time mode, every minute of real time represented one hour of system time. In this mode, the daily normal operation of the system were simulated in 24 minutes of real time. However, all aspects of the normal daily operation of the system were simulated during this experiment. The only exception were the difference in timing and the use of emulated data sources.

8.1 Hardware Setup

The load management simulator consisted of a central unit, remote unit and data sources. Five microcomputers, six monitors, two line printers, four modems and a terminal consisted the main components of the system. The central unit discussed in Chapter II, was the same during the simulation except for eliminating the use of a microcomputer (IBM-AT/PC) as a front-end for load data collection. Functions of that unit were carried out by the main unit (IBM-RT/PC).

The remote unit was simulated by using an (IBM-AT/PC). The control operation of the remote unit was replaced by a graphical panel on the color monitor of that computer. This remote unit was attached to one of the line printers, meanwhile the other printer was attached to the main unit. The remote unit was connected to the central unit by a dial-up telephone line and two modems.

The overall set-up of the system is illustrated in figure 30.

8.1.1 Central Unit

The central unit consisted mainly of the main computer unit (IBM-RT/PC) and its communication accessories. The front-end computer (IBM-AT/PC) used for data collection was eliminated because of the need for that computer for other purposes during the simulation, and because the number of users of the system was very small, and hence, the system speed was high enough to carry out the load data collection function efficiently. A special communication package was used for this purpose which has minor differences from that used on the IBM-AT.

All functions of the central unit which has been discussed in Chapter II were carried out exactly during the simulation process. This has included data collection, filtering and archiving, load forecasting, load modelling, scheduling of load control, information display and

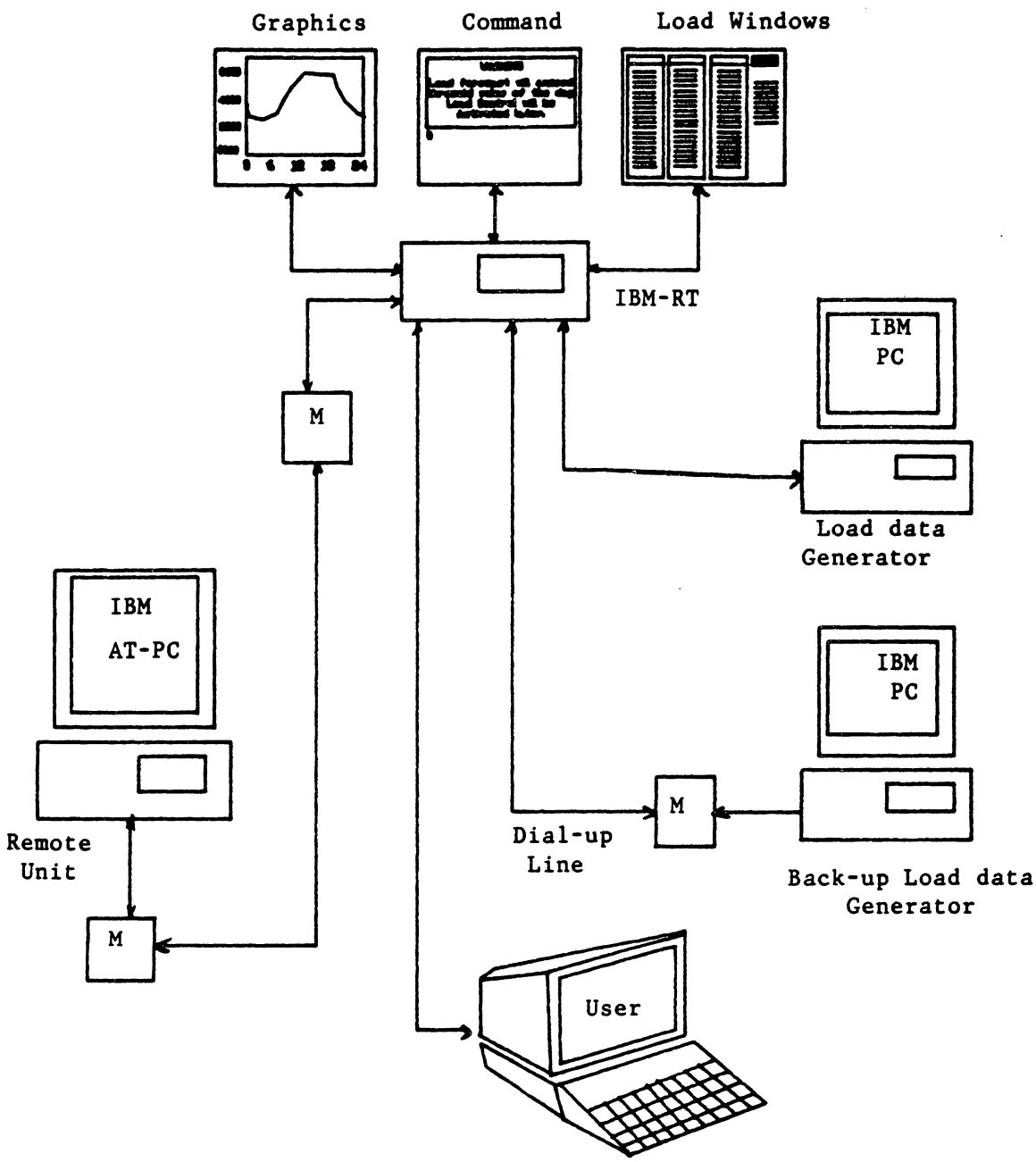


Figure 30. Overall set-up of the IILMS during the simulation process

alarm processing. The decision making process, which is the parent process of all functions, also resided on the central unit.

Five out of the six available serial ports on the IBM-RT were used during the simulation. One was used by a terminal for a user, two for load data collection over hardwired and back-up dial-up line, one for the graphics terminal, and the fifth for communicating with a remote unit over dial-up telephone line. This does not include the console terminal which has its own keyboard, monitor(s), and mouse adaptors. The need for the external graphics terminal arose when the operating system (AIX V1.1) failed to support color graphics on the console terminal. However, the newly released version of the operating system (AIX V2.0) can support color graphics on IBM monitors [4].

8.1.2 Remote Unit

An IBM-AT was used as the heart of the remote unit. This unit was connected to the central unit by two auto-dial auto-answer modems over a telephone line. Transmission of control signals to residential load blocks was simulated by a graphical panel on the color monitor of the IBM-AT computer. Blocks of waters heaters and air conditioners were presented by two sets of blocks with two different colors on the monitor. A red spot on each block indicated that the unit is "ON", a green spot indicated that it was naturally "OFF" (due to diversified demand), and a flashing green indicated that the unit was "forced OFF" as a result of load control schedule. The load blocks that are naturally "OFF" are selected randomly out off all number of blocks. The percentage of these blocks to the total number of blocks equals the diversity factor of the load at that hour.

Remote units were put in an "alert mode" waiting for calls from the central unit. When the call was made, a certain type of dialogue was established between them to exchange information and acknowledgement codes. One of three types of codes was associated to each message to indicate it's type. These messages and signals can be divided into three types:

information signals, signals to start load control and signals to end load control. Information signals were used to display some information on the monitor, and print it on the attached line printer and archive it as a source of information for future activities. After receiving information signals, the remote unit started the preparation to apply the control schedule. When the "start" signal was received, the control schedule was applied and the color panel was used to show the effect of load control schedule on load blocks. This process stayed in effect until the "end" signal was received, and the remote unit returned back to its normal operation.

8.2 Load Data Emulation

One of the microcomputers (IBM-PC) was used to emulate the electric load data signal. A special communication program was developed for this purpose. The emulated hourly load data were generated using actual load data of Virginia Power for 1986. This program reads the load data for the new hour and next hour, and by applying linear approximation, the instantaneous load data is calculated. To avoid unrealistic situations, where load values are increasing or decreasing steadily, a random number that does not exceed ±1% of the load value will be added to it, and this will not affect the overall hourly average of the load data. Other considerations applied to emulate the normal operation of load data generation include:

1. load data transfer was made at the rate of 150 readings per minute;

2. bad or noisy data were generated randomly at the rate of 1% of the time;

3. good data had the same format of that of the voltmeter ("+**.***" where * is a digit 0-9); and

4. special function keys were used to interrupt and resume data generation for certain periods of time.

The reason for the using interrupt keys was to test the ability of the load data collection routines to react properly when the data acquisition system fails to receive data for different periods of time. More discussion on this point is available in a later section in this chapter.

Hardwired connections were used between the central unit and the load data source using two modems. This link was used to represent the actual situation where leased telephone lines (with no dial-tone) are used to transfer load data from the voltmeter to the system. However, the back-up line was represented by a dial-up telephone line and two auto-dial auto-answer modems.

Hourly load data was archived in different databases in addition to the main database used by the forecast algorithm. In order to maintain the size of this database, the data file would be scrolled up at midnight (end of each simulated date) and discard the data of the oldest day. The load and weather forecasts for the new day are inserted at the end of the file, and are replaced by actual data when it becomes available.

8.3 Communications

Communications play an important role in the daily operations of the IILMS. One of our major objectives was the use of modern communication technology to improve the efficiency of load management. Similar to the actual operation of the system, three types of communication links were used during the simulation process:

- data acquisition;

- computer-to-computer communication;

- processing of warnings and alarms.

These three types of links were established between the central unit and other units of the system. The following sections will discuss in detail about each one of them.

8.3.1 Data Acquisition

As it was mentioned earlier, one of the microcomputers was used to emulate the actual behavior of the voltmeter used to transmit load data. That computer was supported by a special communication program written in BASIC. This program was developed to generate and transmit emulated load data using modems in local mode. The settings of communications were:

- use serial part #1 (com1:);
- baud rate = 1200 bps;
- no parity check;
- add a line feed after each carriage return;
- 8 bits of data and one stop bit;
- unbuffered data collection; and
- modems used in local mode.

When the data generator program was started, it activated the serial port for data transfer and modem for communications. The load data generator waited for incoming calls from the central unit. When the call was made, a trapping routine forced the modem to answer calls locally (with no dial-tone). After the establishment of the link, emulated load data were generated and transmitted to the central unit at the rate of 150 readings per minute. Data transfer continued until it was interrupted manually.

The back-up dial-up phone line has similar communication settings. The only difference was the need for dial-tone to establish the link over telephone lines. However, it is important to note that in real life, dial-up lines can not be used for a long time. Our experience has shown that a scrambling signal is transmitted by the telephone company after few hours of establishing the call. This results in a noisy communication, and ultimately dropping the line.

During the simulation process, the back-up line was activated by interrupting load data transfer for 15 seconds using the the interrupt function key on the data generator computer. A special alarm shell was used to detect interruption in load data transfer. This alarm shell is used to track every step of the data acquisition program and it watches for interrupts and bad data. Every time a good data is received, a 15 second timing alarm will be set. If another good data is received within the fifteen seconds period then the timing alarm would be reset and a new 15 second period would be set again. When data transfer was interrupted for 15 seconds, the following actions were taken:

- a warning message was sent to the operator on the console terminal to indicate the failure of the leased line. This message is shown in figure 31.

- the same message was printed on the information center printer.

- the program for load data collection using back-up dial-up line was activated.

- old data collection program was terminated.

8.3.2 Computer-to-Computer Communication

Information transfer between two computers is a little bit different from data collection because there is a two-way communication. Some precautions must be taken to avoid loss of information. For this reason, all types of data transfer from one computer to the other were

*** WARNING ***

The leased-line for load data collection has failed. The system will try to use the back-up dial-up line to resume data collection right now. Please check leased line and modem. If leased-line is fixed please stop this program and start it again.

NOTE: If the dial-up line was dropped for any reason before returning to the leased line, the system will call again.

Time of this message: 10: 5:34
Date now: 2/17/87

Figure 31. Warning message of failure to collect load data over leased-line

accompanied with special codes. An acknowledge signal is sent back to the originator of the code indicating that the message (or data) has been received correctly. If, for any reason, no code or a bad code was received, a special code will be sent back. In this case, the same data or message will be transmitted again by the source. This type of communication is used between the main unit (IBM/RT/PC) and the graphics computer, also between the main unit and remote units.

For the case of the graphics computer, a serial port of that computer was connected directly (hardwired) with one of the serial ports of the main computer. Communication parameters for this link were: 9600 baud, 8-bit data, one stop bit, no parity check and unbuffered data transfer. Similar parameters were used for the communication between the center and remote units except for 1200 baud rate and the use of modems and telephone lines.

8.3.3 Processing of Warning and Alarms

Alarm and warning messages can be transmitted to all or some of the terminals attached to the system in case of hardware/software failure or when certain types of load management activities are expected. Some of these messages can be sent to the console terminal only if it does not have any effect on other users.

During the simulation process, warning and alarm signals were generated automatically using a special shell written in FORTRAN, C and AIX. When the system decides to send any message to the users, the message will be archived in a well-formatted file on the hard-disk. When the file is archived, one of the two AIX-commands- "write" or "wall", was used to send that signal to the specified users. The command "write" will be used to send messages to individual users, while "wall" is used to broadcast messages to all users including the system manager on the console terminal. All connected terminals at the moment of the broadcast will receive the message immediately along with a beeping signal. Reception of the message does not require the user to be logged in, but it required his terminal to be powered on at that

moment. Receiving the message would not interrupt any activity on the receiving terminal, but it will over-write any information on display at the terminal.

8.4 Description of the Simulation Process

The simulation process started by installing the equipment as described earlier and as illustrated in figure 30. When all devices and computers were ready, the following steps were taken:

- load data collection was initiated using the "leased-line". The central computer called the load data emulator and started data collection. When the communication link was established, windows were created over one of the console monitors. Three windows were used to display the 30-second, 15-minute, and one-hour load averages. A small window was used to display the instantaneous load data. Each window was updated whenever corresponding data was available. Figure 32 illustrates the load data display on the console monitor.

- alternate console monitor was activated for entering control commands.

- decision making process was initiated from the console terminal. At the beginning, a signal was sent to the graphics terminal to start and be ready to receive real and forecasted load data for graphical presentation.

- the short-term load forecast was started at the top of each hour (simulation time) by the decision making process, and the load forecast output file would be updated with up-to-date forecasts and errors of previous hours. A sample of the load forecast output file is shown in figure 33.

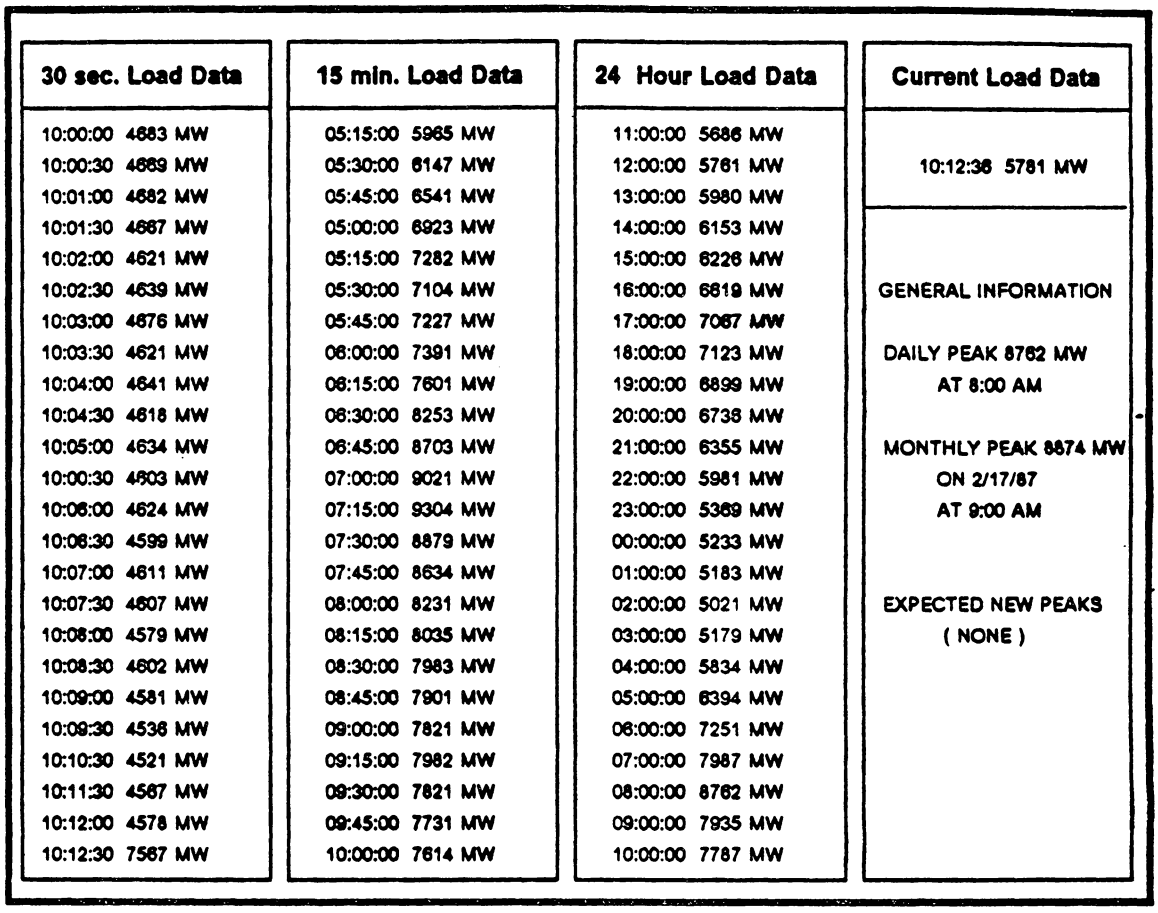


Figure 32. Windows used to display instantaneous and averaged load data

24-Hour Load Forecast

Load & Error values in MW

Hour	Load	Error	Hour	Load	Error
00:00	6181	[-32]	12:00	7449	[ ]
01:00	5865	[27]	13:00	7239	[ ]
02:00	5692	[45]	14:00	7087	[ ]
03:00	5712	[62]	15:00	6935	[ ]
04:00	5734	[33]	16:00	6878	[ ]
05:00	5912	[10]	17:00	7016	[ ]
06:00	6085	[74]	18:00	7191	[ ]
07:00	6448	[96]	19:00	7430	[ ]
08:00	6908	[81]	20:00	7273	[ ]
09:00	7334	[37]	21:00	7078	[ ]
10:00	7301	[ ]	22:00	6840	[ ]
11:00	7599	[ ]	23:00	6678	[ ]

Date: 3/12/1987
Time: 09:05:31

Figure 33. Load forecast output file including errors for previous hours

- load control program was called after the completion of each load forecast. Threshold value of the month was generated or reviewed, and if this value was not exceeded by forecasted data, only a caution message was generated, and no control was initiated. The caution message is illustrated in figure 34.

- at those hours when the threshold value was exceeded a warning message was sent to all users, printed on the console monitor, and sent to the central printer. As shown in figure 34 this message indicates all hours at which threshold value was exceeded.

- load models was called after that. The load control program decided the length of the control period, starting time and control strategy. Load models were called back again to get final results about load control schedule. Reductions and paybacks for water heaters and air conditioners were displayed at the console monitor as shown in figure 35.

- at the time of starting load control, special signals were sent to remote units. These signals initiated the dispatch of load control which was represented by color spots on each load block on the screen. A red spot was used to indicate that the block was ON at that moment, a green spot for naturally OFF, and flashing green for blocks forced off by the controller.

- all steps were repeated every hour (system time).

For more datails on the hardware and software design, you can refer to Baba and Rahman [23,24].

CAUTION

Forecasted Load data will not exceed threshold data of the month for the rest hours of the day, and no load control actions are planned. This message will be updated every hour.

Threshold value of the month = 8918 MW

Time now: 14:00:41
Date: 2/18/87

!!!!! WARNING !!!!!

A new peak load that exceeds the threshold of the month is expected today. The threshold will be exceeded as follows:

Threshold value of the month = 8918 MW

Expected load = 9026 MW at hour 18:00
Expected load = 9074 MW at hour 19:00

Direct Load Control will be initiated at hour 17:00 today. A load control schedule has been prepared. For more details enter the command "control".
This message may be modified later, so please keep watching

Time now: 11:00:37
Date: 2/19/87

Figure 34. Caution and Alarm messages related to load control

Load Models Output

[Water Heater] Reductions/Paybacks per unit

Hour	18:00	-0.67 kW	Reduction
Hour	19:00	-0.58 kW	Reduction
Hour	20:00	+0.89 kW	Payback
Hour	21:00	+0.35 kw	Payback

Total number of units = 80,000

[Air Conditioners] Reductions/Paybacks per unit

Hour No control of Air conditioners in Winter

Time now: 14:01:09
Date: 2/19/87

Figure 35. Output file of load models

Chapter IX

IMPACTS OF THE IMPLEMENTATION OF LM SYSTEM

The implementation of the Intelligent and Integrated Load Management system (IILMS) has different impacts on the electric utility, the large customers (e.g., electric cooperatives) and the consumer. In this chapter, some of the major impacts of this implementation will be discussed in detail. The final evaluation of the system will depend heavily on the benefits and shortcomings of applying direct load control.

9.1 Evaluation of Benefits

There are many benefits that can be gained by applying the IILMS. These benefits can be summarized in the following.

1. For the Electric Utility

- Generation system benefits
  - capacity requirements
  - economic benefits
- Transmission system benefits
  - reduction in contingencies
  - distribution system benefits

2. For large customers
   - reduction in capacity charges (coincidental peak changes)
   - reduction in total demand due to load control
3. For the customer
   - reduction in rates due to incentives
   - reduction in total monthly demand

9.1.1 Benefits of the Electric Utility

Benefits of the electric utility are the most important factors in the load management program. These benefits will be reflected on all other users or customers in the terms of lower bills. Better services can be another benefit of applying load management on system loads.

9.1.1.1 Generation System Benefits

- Capacity Requirements

The main purpose of applying the load management system is to reduce the peak demand of the electric utility. If the load management program could carry out this goal effectively then it can result in the elimination or reduction of new generating capacity. Savings associated with this elimination can cover the expenses of installing the load management system. However, the realistic evaluation of load management must be consistent with the normal generating capacity planning of the utility. The considerations and practices of these generating capacity plans vary across the electric utility industry, and reflect the unique nature of each power system.

Schedules of generating unit installation can be set up with the system load shapes modified to represent the effect of direct load control strategies. If the combination of the modified system load shapes with the unit installation schedule results in better annual reliability levels then the unit installation schedules can be delayed until the reliability target is reached again. The target reliability level can be set by analytical studies of the generation/load systems. Different computer programs are available in the market for this purpose [25].

- Economic Benefits

Short and long-term benefits can be achieved through the implementation of the load management system. The short term benefits are usually described as the economic benefits to the electric utility in the period before capacity additions are deferred, and the long-term after the deferral or elimination of the first planned capacity.

These benefits include the increase in revenue from system sales to other utilities based on the reduction in system peak demand. However, it is important to realize that there are many uncertainties associated with the system's ability to make additional sales based on reductions in peak load using load control.

The usage of load control as an "Emergency Capacity" is also one of the added benefits to the utility. In the cases of generation deficiencies the electric utility can control customers loads even for longer hours than normal, even though some customer inconvenience might result. This inconvenience is less important than the probability of wide-spread and more serious problems which might result if the control action was not taken.

For long-term benefits, the reduction in capacity requirements and the delay in installing new generators is the main beneficial factor in this regard. However, it is essential for every electric utility to study the economic benefits from the reduction of capacity requirements, and the cost of installing and operating the load management system.

9.1.1.2 Transmission and Distribution System Benefits

Transmission and Distribution System is not expected to benefit significantly from the installation of the load management system. However, two benefits could be gained in the short-run from this installation. These are:

1. Reduction in the severity of contingencies. Load control can be used to reduce thermal loadings or voltage drops in the case of a disturbance due to contingency. The success of using load control to reduce the severity of contingencies depends on the ability to diagnose the disturbance and to determine the corrective action very quickly.

2. Improve the flexibility in scheduling required maintenance outages. Risks of injuries to customers or employees of the electric utility governs the scheduling of maintenance outages. Risks are minimized at times of low demands on the systems. The ability to reduce the demand using load control will reduce the risks, and thus, improve the flexibility in scheduling maintenance outages.

For long-term benefits, some new facility installation can be deferred if the load management system could reduce the growth of peak demand. Such deferral or cancellation of a new installation will reduce capital investments. The ability of the load management system to permit proper control on the basis of local load areas is a pre-condition for the long-term benefits. New facility installation which might be affected by local control involves the construction of new high voltage transmission lines and new substation transformers with higher capacity.

9.1.2 Benefits to Electric Cooperatives

The installation of a load management system by an electric cooperative buying the electrical energy from one utility or more can benefit greatly. Mainly, cooperatives are charged for the "coincidental" peak can reduce their charges by high percentages if they could reduce their contribution to the system peak. In several states, cooperatives can reduce their monthly bill by (10-15) thousand dollars for every MW of reduction in their share of the monthly peak. For those cooperatives purchasing hundreds or thousands of megawatts, a reduction of 10% of their demand at peak time may lead to savings in millions of dollars.

The figures shown above provide encouragement for installing load management systems for the coops, but a feasibility study of benefits must be made prior to the installation of the system. Although, the cost of the Intelligent and Integrated Load Management System is very low compared to the savings it may produce, it is important to include other expenses in this regard. The cost of transmitters, receivers and other communication devices in addition to the high cost of maintenance must be considered.

For certain cooperatives already having a SCADA system, the load management system can be integrated with the network of the SCADA system. Such integration may reduce both the capital and running costs of the installed load management system.

Cooperatives can also benefit from using load control by reducing the total energy purchased in a month. This reduction comes as a result of the difference between load reduction due to load control and the payback demand following the control. Most tests made on residential load control have showed that the total payback energy will not exceed 90% of the total reduction in energy during the load control [25].

The ability of the load management system to forecast the monthly peak load and to take the proper action in time is the major factor in the success of the cooperative to save money. In addition to that, if more than one cooperative has load management systems, then it is important to corporate together in order to guarantee the success of the control process. The failure of coordination between existing load control systems on the same utility may cause great losses to each cooperative and to the electric utility at the same time. Contradictions in control plans for different cooperatives will be discussed later in this chapter.

9.1.3 Benefits to the Consumer

Although load control may cause some inconvenience to the customer, he might gain some benefits from it. These benefits will take the shape of savings in money due to reductions in the monthly bill he receives. Such reductions include:-

- incentives paid by the supplier for customers who accept to participate in the load control programs.

- reduction in the total consumption of electric energy due to load control. The difference between reduction in demand during the control period and the payback demand following that period cause such reduction in total consumption.

Direct incentives include the following:-

- Cash grants
- Rebates
- Buyback programs
- Billing credits
- Low-interest or no-interest loans.

In some cases, an additional type of direct incentive is the offer of free equipment installation or maintenance in exchange for participation.

9.2 Evaluation of Expenses

The installation of the load management system will cost the installer in different ways. These expenses include both capital and running costs. The ability of the load management system to payback all of these expenses and to yield extra savings is the motivation for the installation of such a system. The following sections will illustrate some of the costs involved in the implementation of load control.

9.2.1 Equipment Costs

The load management system has two basic components, the central units and the remote units. The central units include microcomputers, communication devices, surge protectors, digital to analog converters and other electronic devices. High power signal transmitters are also a part of the central control unit. The estimated cost of the central

controller can range from several hundreds of thousands of dollars to a few million dollars. The size of computers and the cost of the software implemented on these computers takes the highest percentage of the cost of the central units.

The remote controllers costs range from $80 to $140 per customer [26]. This includes the cost of receivers, switches and installation. It is important to note that the higher the penetration level the higher the total cost of the system. Also, since the cost of digital and communication devices changes rapidly from time to time, it is essential to include these changes in any study of cost-benefit analysis.

9.2.2 Maintenance Cost

Maintenance cost represents the highest percentage of running-cost of the system. As it was shown earlier, the maintenance cost is a function of the availability of loads under control. Also, maintenance cost is expected to increase by time due to deterioration of components. Training of personnel on operating and maintaining the system can be considered in this category.

9.2.3 Customer Incentives

Direct incentives are used by the companies to encourage the customers to participate in the load control program. Various types of direct incentives are applicable to many of the cost control options. These incentives can take the form of a lower kWhr, monthly bill credit, a lump sum annual payment, or one of the other forms discussed earlier.

9.3 Impacts of Independent LM Programs

Most of the large load management systems that exist in the electrical industry now are operated by the generating utilities. Other LM systems are operated by large customers and have a very low effect on the total load of the system. In most cases, the level of load changes (reduction or payback) is still below the noise level of the total demand. However, in the last few years, many of the wholesale customers have shown their interest in possessing their own independent load management systems. Such interest arises after the great success of the preliminary tests implementing small size LM systems. These systems have shown the ability to yield great savings to the large customers by reducing their share in the system peak.

Most of people may have ignored the fact that the success of these systems was based on the uniqueness of these systems in their utilities. In other words, the implemented load management system was the only one in that utility. The existence of more than one independent LM system in the same utility will not guarantee, in any case, that each system will yield the same savings as if it were alone. Moreover, this situation may cause losses for some or all of those customers and to the utility itself. The reason for that is due to the isolated trials by each LM system to modify the load at the same time. If each system is working independently, then there is a good chance of creating undesired load shape as a result of net changes of all systems.

One of the most critical and destructive results of independent load management programs is the creation of a "Shifted Peak". A shifted peak can be created when the total reductions of all LM systems has exceeded the required level, and the total payback demands "overshoot" the limit at a later hour creating a new peak. Figure 36 illustrates this case for a utility with two independent load management systems.

The primary solution of this problem relies on the ability of these LM systems to transfer information to each other. Also, the integration of all independent LM systems with the central controller of the utility represents the ultimate solution for the problem. If these systems failed

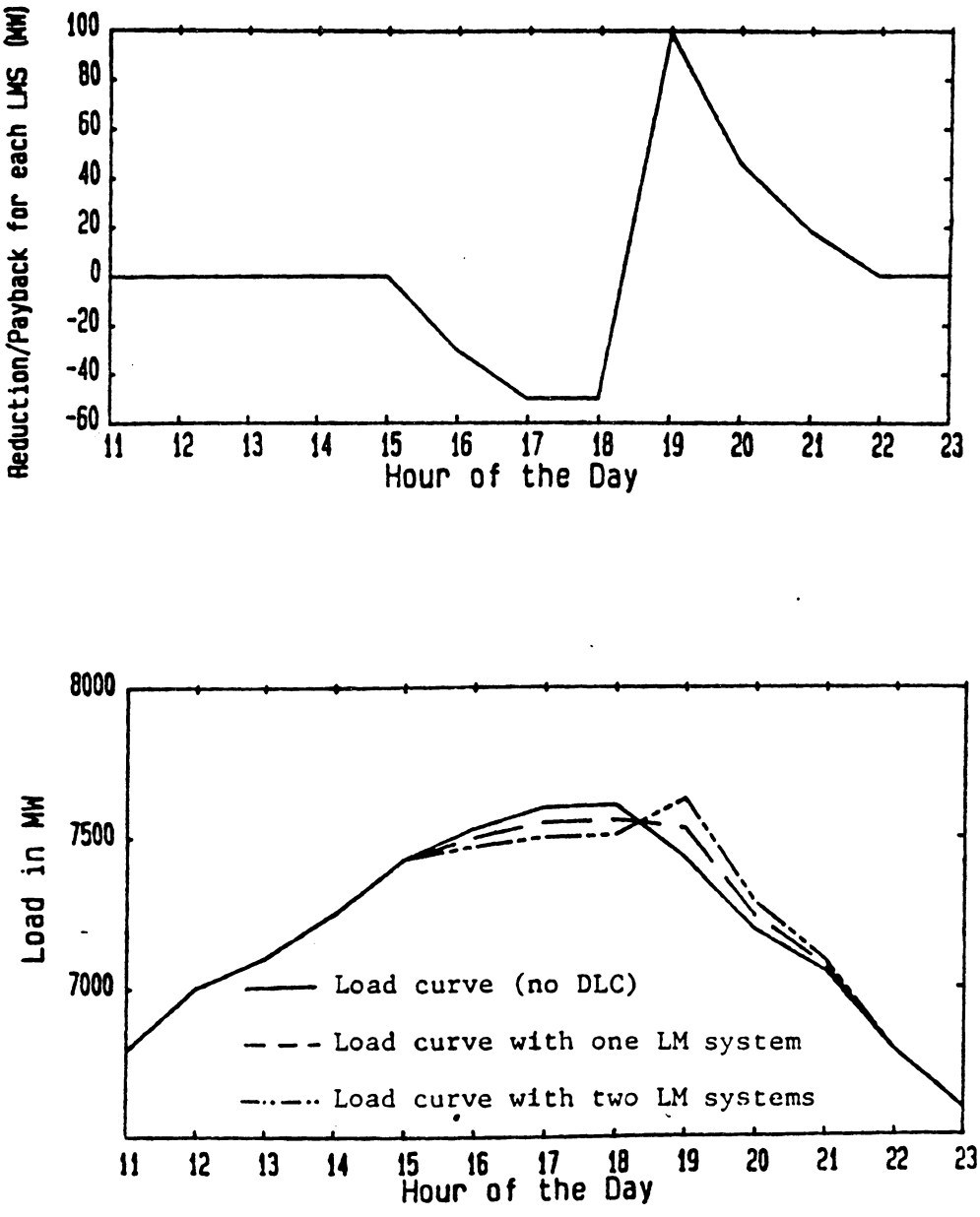


Figure 36. Creation of a "shifted peak" by two independent LM systems

to cooperate with each other and with the central controller, all benefits of these systems will be lost. Since there is no guarantee at this moment that such cooperation will be available, and because some of these systems may not have the capability to transfer information to other systems, it was important to add some intelligence to the designed LM system to avoid this problem. Even though it is very difficult to predict what other systems are going to do, there is the capability to sense their actions. As it was described in Chapter II, the system keeps monitoring the total system loads on a real-time basis. When load control programs are about to be activated, the control program will keep monitoring changes in the total system demand. If these changes are exceeding certain levels then the control plan will be modified. Such modifications include changing the control strategy, time of control, period of control, and the number of blocks to be controlled at anytime.

The previous methods have shown its ability to generate successful load control programs during the simulation process. However, it is not expected to yield the optimum reductions all the time, but it will help avoiding bad decisions.

Chapter X

CONCLUSIONS AND RECOMMENDATIONS

A complete intelligent and integrated load management system has been designed, simulated, and evaluated. The design process has included the use of expert systems to increase the efficiency and accuracy of the system and to eliminate the need for mainframe computers to carry out the functions of the system. Direct load control has been used as the main tool for achieving certain modifications of system load shape. Residential water heaters and air conditioners were considered in this study.

This research extends the horizon of using computers and other communication devices in the area of energy management. Also, the designed system included for the first time both of the conventional types of load management systems; the load control center and the load forecasting system. In addition to that, the whole decision process and information transfer has been included so that the need for human expertise or operator intervention has been reduced. Furthermore, the use of microcomputers for carrying out all functions of the system efficiently would aid in promoting load management. Also, the practical concept of integrating the designed load management system into the planning process and the normal operation

of the power systems control center was demonstrated through the use of modern information technology and software interfaces.

The development of new methods of the major functions of the system were presented in this study. Also, developed were the interfaces which make these functions act in a hierarchical form and enable the transfer of data effectively. Based on the simulation results of the system operation and the discussion presented in this dissertation, it can be concluded that:-

- Multi-tasking, multi-user, fast microcomputers can be used for developing intelligent load management systems.

- With proper communication hardware and suitable software, intelligent load management systems can operate independently as isolated systems or part of the power system control centers.

- Data related to system loads or weather conditions can be collected automatically by the system continuously or at regular times. In cases of failure, the system has the ability to repeat the process, use other available devices, and/or send alarm signals to the system operator.

- A rule-based algorithm has been developed to generate one to twenty four hour load forecast. This algorithm has improved upon the knowledge-based algorithm developed by Rahman and Bhatnagar [21]. Less computing time and smaller database and higher accuracy are the major advantages of this algorithm. The method of extracting rules and evaluating factors affecting the forecast using off-line techniques and a self-revising mechanism are some other enhancements of the knowledge-based algorithm.

- This short-term rule-based load forecast algorithm can predict the exact time and magnitude of the system peak loads with high accuracy.

- Use of a self-revising mechanism for the short-term load forecast has shown significant improvements in the load forecast algorithm, and a very efficient replacement for long and complicated computational methods.

- Load models were developed to determine the normal diversified demand of water heaters and air conditioners, determine the impact of different load control strategies, and determine the impact of load control on the total system load. These models were developed using rule-based algorithms where a standard load shape of every season can be modified to encounter changes in weather conditions. This method has shown the ability to generate results with errors less than 5% from experimental results.

- Load threshold value of the month which is the limit beyond which DLC will be dispatched is determined by multiplying the minimum of the monthly peaks of the last three years by 0.95. Test results for load data of Virginia Power for the years 1980 to 1986 have shown that none of the monthly peaks have been missed. The maximum number of dispatching direct load control was 5 times per month, and the average was three.

- Simulation results of using different load control strategies have shown that improving the penetration level of customer loads does not mean always improving total load reduction. These results indicate that peak reductions reach saturation level beyond certain limits. These limits differ from one utility to another depending on the general characteristics of total load shape of that utility.

- Groups of alternative load management options must be considered because one option may produce a load shape impact that partially cancels the impact of another option.

- The success of load management systems depends on the ability to exchange information about their control plans. In the last few years, a great interest has been shown by the wholesale customers to implement their own (independent) load management systems. Currently, the impacts of existing customer LM systems does not exceed the noise level of the generating utility. Unpredictable impacts might happen when all planned customer systems are implemented.

10.1 Recommendations

Most of the concepts implemented during this research are part of the process of using modern technology in power systems, and hence require more testing, improvement, and refining. The author expects that more developments can be achieved by further research for three reasons. First, this is the first time a complete load management system has been developed where the control center has been put together with an information center and load forecasting system. As with any new system, more experience and technology development will lead to better systems. Second, the system operation has been simulated but never tested under normal operations, thus more improvement may be required in order to solve some real problems. Third, the expert systems approach has been used for the development of most functions of the system. Current improvements of this relatively new approach promises great results in the near future, and this will be reflected in the results of each function. In addition to these points, the availability of more resources, experience, data, and time will make it possible for further exploration of the concepts used during this study.

Further research is recommended for the following issues:

- Long-term load forecast which has the ability to predict with reasonable accuracy the system load in general, and the system load peak for one week or more, in particular. Such forecasts will improve the certainty of decisions made by the control algorithm, and reduce the number of trials needed to guarantee the reduction of monthly peak.

- The use of local load forecasts in order to generate the total system load forecast is recommended. The use of local weather conditions other than average values for the whole service area of the utility is expected to yield great improvements in the forecasted results.

- The study of more residential or other loads of the system in order to improve the availability of controllable loads for the whole year. Space heaters need more experimental testing and data analysis in order to be considered as a practical controllable and predictable load.

- The applications of the system can be widened by including more types of load management (i.e., energy storage) in addition to load control. Using direct load control alone has many limitations and sometimes involves some risks which can be prevented by using more types of load management. This may require more experimental testing, data collection, and also improvement of tools used for this purpose.

- Although the method for integrating the load management system in the normal operation of the power system control system has been presented and discussed in this study, the real data of such integration is not available yet. This integration is a wide field for more study in order to include the LM system in the daily operations of the center, and for the study of the future impacts on the utility.

- An economic analysis of the relationship between savings and the penetration level of loads is recommended. The author recommends that a separate analysis must be done for every utility because of the differences of load types of each utility and total load shapes of them.

Chapter XI

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